PSNH FINAL INTERCONNECTION REPORT
FOR
CUSTOMER GENERATION

UNH TURBINE

SESD SITE NO. 1080

July 14, 2008

CONTENTS

VII. DRAWINGS

A. PARTIAL ONE-LINE DIAGRAM (SK-PCM-1080-2)

I. INTRODUCTION

A study has been performed to determine the impact of this proposed facility on the PSNH system. All technical analysis was based on the equipment listed under Section II, and the facility arrangement illustrated on partial one-line diagram SK-PCM-1080-2. Where actual site-specific data was not readily available, estimated or "typical" values were utilized in any required calculations. Any deviation from the listed equipment and/or the illustrated configuration may have significant safety and/or technical ramifications. Consequently, if changes are anticipated now or in the future, PSNH should be informed immediately so that the requirements and recommendations contained within the report may be revised where necessary. This procedure will ensure that the Developer is informed of PSNH requirements in a timely fashion and should eliminate the delays and expense which could otherwise be experienced by the Developer.

II. DESCRIPTION OF MAJOR COMPONENTS

A. Description Of Facilities

The Developer will install a 4.6MW/5.75 MVA, gas fired, synchronous generation unit at a site near the existing tie to generators G1 and G2 at UNH in Durham, New Hampshire.

B. Electrical Components

1. Generator (1) - Synchronous, 3 phase, 4 wire, 4160V, 60 HZ, 4 pole, 0.8 pf, 1800 RPM, 5750 KVA.

2. Excitation – Permanent Magnet, brushless

3. Voltage Regulators – Solid State, 3 phase sensing

4. Circuit Breakers – (Unspecified vacuum breakers)

5. Generator Step Up Transformer: 1- 5,000 KVA, 19.92/34.5KV reactance grounded wye-4.16KV delta, with an estimated 7% impedance.

6. High Side Neutral Grounding Reactor, per specifications in section IV.A.3.

7. High Side Interrupter #1 - The first of two required high side interrupters, this one a vacuum circuit breaker designated "52-T3", will be required on the high side of the GSU. It was estimated that this circuit breaker will be rated 1200 amps continuous, 16KA symmetrical interrupting at 34.5 kV, and will be a 38 kV class device. It must be manufactured to ANSI standards.

8. High Side Interrupter #2 - A required second high side interrupter, located at the tap of the PSNH 380 line, will be a G&W Viper vacuum recloser with a SEL 651R control, 560A rating, 12,000A interrupting.

9. High side disconnect switch – In line disconnect switches will be required on the UNH side of high side interrupter #2.

C. Mechanical Components

1. (1) Solar Mercury 50, Combustion Turbine

III. PSNH REQUIREMENTS - GENERAL

A. Safety Considerations

1. The connection of the facility to the PSNH system must not compromise the safety of PSNH's customers, personnel, or the owner's personnel.

2. The generating facility must not have the capability of energizing a de-energized PSNH circuit.

3. An emergency shutdown switch with facility status indicator lights, and a disconnecting device with a visible open shall be made available for unrestricted use by PSNH personnel. The operation of this switch shall isolate the facility from PSNH with the high side interrupter. The status lights, mounted with the shutdown switch, shall be located outdoors at a position acceptable to PSNH Operating Division personnel. If the status lights are located in a cabinet, the lights shall be visible from outside of the cabinet. A red light shall indicate that the facility may have generation connected to the PSNH system. A green light shall indicate that all generation is disconnected from the PSNH system. The lights shall be driven directly from auxiliary switches located on the facility's breaker(s). The disconnecting device with visible open shall be located between the PSNH system and the facility's generation.

4. Dedicated relays must be reserved for PSNH required functions. These relays will provide no other functions except for PSNH required functions. PSNH will determine, at the Developer's expense, only the voltage, frequency and current set points for the PSNH required protective functions. The Developer is responsible for determining and applying the complete settings of these relays.

5. A PSNH approved testing company will be required to verify the proper functioning of those protective systems required by PSNH. This work will be performed at the Developer's expense.

6. The generating facility has full responsibility for ensuring that the protective system and the associated devices are maintained in reliable operating condition. PSNH reserves the right to inspect and test all protective equipment at the generator site whenever it is considered necessary. This inspection may include tripping of the breakers.

7. The short circuit interrupting device(s) must have sufficient interrupting capacity for all faults that might exist. The PSNH system impedance at the facility will be supplied on request.

8. All shunt-tripped short circuit interrupting devices applied to generators must be equipped with reliable power sources. A D.C. battery with associated charging

facilities is considered a reliable source.

9. All synchronous generator facilities must be equipped with battery-tripped circuit breakers.

10. Any protection scheme utilizing AC control power must be designed in a fail-safe mode. That is, all protective components must utilize contacts which are closed during normal operating conditions, but which open during abnormal conditions or when control power is lost to de-energize the generator contactor coil. These schemes may be utilized only with non-latching contactors and may not be used with synchronous generators.

11. A complete set of AC and DC elementary diagrams showing the implementation of all systems required by PSNH must be supplied for PSNH review. These drawings should be supplied as soon as possible so that any non-conforming items may be corrected by the Developer without impacting the scheduled completion date of the facility.

12. All voltage transformers driving PSNH-required protection systems must be rated by the manufacturer as to accuracy class, and must be capable of driving their connected burdens with an error not exceeding 1.2 percent.

13. All current transformers driving PSNH-required protection systems must be rated by the manufacturer as to accuracy class and must be capable of driving their connected burdens with an error not exceeding 10 percent at maximum fault requirements.

14. All PSNH-required protective relays, and any other relays which PSNH might be requested to test, must be equipped with test facilities which allow secondary quantity injection and output/input contact isolation.

15. All PSNH-required protective relays designed to trip generation off-line must do so directly through hard-wired connections. Trip signals shall not be redirected through programmable logic controls or other microprocessor based controllers.

16. It is not the policy of PSNH to maintain a stock of protective relays for resale to facility Developers. Since many protective devices have delivery times of several months, Developers are strongly advised to order them as soon as possible after PSNH type-approval is received.

17. Protection of the generating facility equipment for problems and/or disturbances which might occur internal or external to the facility is the responsibility of the Developer.

18. No operation of the facility's generation is allowed until all requirements in Sections III and IV of this report have been met, and all systems required therein, are in place, calibrated, and, if applicable, proven functional. This requirement may be waived by PSNH for a given system if generation is required to demonstrate the proper functioning of that system.

B. Service Quality Considerations

1. The connection of the facility to the PSNH system must not reduce the quality of service currently existing on the PSNH system. Voltage fluctuations, flicker, and excessive voltage and current harmonic content are among the service quality considerations. Harmonic limitations should conform to the latest IEEE guidelines and/or ANSI standards.

2. In general, induction generators must be accelerated to "synchronous" speed prior to connection to the PSNH system to reduce the magnitude and duration of accelerating current and resulting voltage drop to PSNH customers to acceptable levels.

3. In general, synchronous generators may not use the "pull-in" method of synchronizing due to excessive voltage drops to PSNH customers.

4. Power factor correction capacitors may be required for some facilities either at the time of initial installation, or, at some later date. The installation will normally be done by the Developer at his expense.

5. Certain facilities, having installed capacity similar in magnitude to connected circuit load, may require that control modifications be made to tap changers in the electrical vicinity. Should they be necessary, the modifications will be made at the Developer's expense.

6. Automatic reclosing of the PSNH circuit after a tripping operation may occur after an appropriate time delay. If additional voltage blocking of automatic reclosing is required, it will be added at the Developer's expense.

C. Metering Considerations

1. Except for protection/control and metering voltage sensing and generator and/or capacitor contactor supply voltage, no unmetered station service AC shall be taken from the station service transformers.

D. Other Considerations

1. Operationally, the ESCC requires the following:

In addition to telemetry per section IV.D:

- When generating onto the grid, the Station Operator is to report expected output for the following day, outage and return times, and significant limitations to the PSNH dispatcher.

- Dates for planned annual inspection along with any flexibility in the planned period in accordance with NEPEX Operating Procedure #5.

- Report all generator trips caused by relay action, as well as the associated relay targets, to the PSNH dispatchers.

IV. PSNH REQUIREMENTS - SPECIFIC

A. System Configuration and Protection

1. The facility must be arranged and equipped as per partial one-line diagram SK-PCM-1080-2.

2. The following protective functions must be supplied and connected to automatically trip, alarm, or block close on at least the breakers as shown. These devices must be utility grade as approved by PSNH. Current plans are to use a SEL 351-7 numerical relay.

51	- Phase Overcurrent, Trip Hi Side 52-T3
51G	- Residual Overcurrent, Trip Hi Side 52-T3
51N	- Bank Neutral Overcurrent, Trip Hi Side 52-T3
81O	- Overfrequency, Trip Hi Side 52-T3
81U	- Underfrequency, Trip Hi Side 52-T3
27	- Undervoltage, Trip Hi Side 52-T3
59	- Overvoltage, Trip Hi Side 52-T3
51V	- Voltage Controlled Overcurrent, Trip Hi Side 52-T3
59L	- 3 Phase, Line operating overvoltage protection, alarms then trips Hi Side 52-T3
27L	- Block close of 52T3 for de-energized PSNH system
32	- Reverse Power, Trip Hi Side 52-T3

3. The facility generator step-up transformer (GSU) must have a 19.92/34.5KV Reactance Grounded Wye-4.16KV Delta configuration. The following preliminary neutral reactor, information is based on a 7.0% 5000 KVA GSU. The final GSU impedance must be confirmed prior to ordering the reactor.

Applicable Standard:	ANSI/IEEE Std 32-1972 (Reaffirmed 1990)
System:	34.5KV, 60 Hz
BIL:	200KV
Insulation Class:	25KV
Rated Thermal Current:	250A for 10.0 seconds
Reactance:	47.0 ohms at 60 Hz

(Also specify either Outdoor or Indoor Service, as required)

B. System Metering

1. The facility must be arranged and equipped with the three element bidirectional metering system as shown on partial one line diagram SK-PCM-1080-2.

2. All cost of metering equipment in excess of cost normally incurred by the Company to provide metering for the Developer's Standard Rate shall be borne by the Developer.

3. The Company shall furnish (at the Developer's expense), read, maintain and own the revenue metering equipment.

4. The Company shall meter power delivered to the Developer by registration through the

multifunction meter in the forward (delivered) direction and shall meter net generation by registration through the multifunction meter in the reverse (received) direction.

5. The Company shall assemble the metering cluster, install the meter, and perform a site analysis to verify correct metering.

6. The Developer shall hang the metering cluster and make primary and secondary connections under the direction of a Field Meter representative.

7. The Developer shall provide and maintain an analog phone line that will be connected to the multifunction meter modem. The phone line may be a dedicated line or connected to a line sharing device such that the Company has unfettered access to the metering data through remote interrogation on a daily basis.

8. The physical location of the metering equipment must be approved by the Company and the Developer shall allow the Company reasonable access to the metering equipment for but not limited to meter reading, meter testing and meter maintenance.

9. Three phase, four wire, wye 35 kV primary metering similar to distribution standard DTR 35.821 with the following components shall be installed:
   a) One (1) Multi-function meter with load profile memory, telephone modem and reactive measurement capability, stock code 181807 Group 997.
   b) Three (3) single phase metering outfits, 34.5 kV insulation class, 200 kV BIL, Current Transfer Ratios 100/200:5, 0.3B1.8, RF 1.5, Voltage Transformer Ratio 175:1, 0.3 X-ZZ, stock code 166837.
   c) Three (3) 900A inline disconnect switches and associated wire, connectors, and hardware.
   d) One (1) thirteen terminal meter socket with a pre-wired ten (10) pole test switch, equivalent to a Milbank SC2420-RL-21 or Durham 1008432, stock code 166777.

10. The current transformer ratio for the metering outfits shall be set to 100:5 for net generation or customer load at the delivery point up to 9000 KVA.

C. Primary Interconnection

In addition to the primary metering addition per Section IV.B, the anticipated primary work is the following, which resulted from the operating study for this site, with input from the Developer:

- Add recloser 380X6 and its control tapping the PSNH 380 line, two voltage transformers (one on each side of the new recloser), along with in line disconnects on the UNH side of the recloser.

- Add a line side voltage transformer and necessary control equipment to block (or allow synchronism check) automatic reclosing of the Madbury Substation 380 breaker if the line is energized.

- Move the in-line three phase load break switch 380J4 to the Madbury side of the new 380X6 line tap.

D. Telemetry

Telemetering must comply with OP-0045, including:

1) The selected SCADA RTU must communicate with the ESCC SCADA host computer using the Landis & Gyr Telgyr 8979 protocol. RTU and vendor version of the 8979 protocol must be backward compatible to the Landis & Gyr Telegyr 8979 Revision A (document 1008979000) used in the ESCC SCADA Host. If feasible, the developer may use the existing UNH-Gen RTU to supply the data.

2) Provisions will be made to allow communications with both the ESCC and the Backup Control Center. This will require two DDSII phone circuits
(See OP-0045 for modem specifications.):
One from UNH to 44 West Penacook, Manchester NH
One from UNH to 1985 Blue Hills Avenue, Windsor CT

3) Telemetered data will include:
Instantaneous net MW adjusted to the delivery point
Instantaneous MVAR adjusted to the delivery point
High side voltage as measured on the generator side of the delivery point.
The breaker status of each individual generator, and in the case of combined units, the status of a single breaker, which has the ability to isolate the combined units (in this case both 52-T3 and G3)

4) While not specifically called out in OP-0045, Relay Alarms, DTT Alarms, and permissive switch status should be brought into the RTU.

E. System Operation

PSNH has determined, by load flow studies, that it is acceptable to export a maximum of 5.75 MVA from this location. The voltage at the interconnection point between PSNH and UNH shall be kept between 101.5 % and 103.6 %. A voltage of 102.0 % shall be scheduled at the delivery point. The generation shall have enough regulation capacity (produce or absorb VARS) to hold the scheduled voltage. The results of the load flow study, although producing exact numbers, shall be only used as a guide to predict system response. Actual system performance shall be verified when the installation has been completed. If adverse system conditions are created as a result of this facility, they shall be rectified expeditiously at the Developer's expense.

PSNH reserves the right to request adjustment to generator operation, such as scheduled voltage, to optimize system performance due to future changes to the PSNH system.

V. PSNH PRICE ESTIMATES

The following estimates for labor, materials, and overheads are supplied as an aid to the Developer for financial planning purposes. Should the Developer elect to have PSNH perform any of the work described in the estimates, actual cost will be billed for any work performed.

Authorization for PSNH to perform any of the work or supply any of the equipment described below must be forwarded to the Supplemental Energy Sources Department along with a minimum payment covering 50% of the estimated labor and 50% of materials cost. PSNH will neither perform work nor order materials until this requirement has been met.

A. System Protection

1. All protective relays at the generator plant will be purchased by the Developer. PSNH must be notified as to exact relay model numbers proposed before ordering to assure that proper setting capability exists for interfacing with the PSNH system.

SUBTOTAL	$ 00.00

2. Engineering - PSNH review of control circuits, material specifications and development of PSNH required relay settings at the site, as well as a review of related protective equipment on the circuit supplying the site. Develop coordinating settings for the 380X6 Viper control, and program the recloser control.

SUBTOTAL	$ 7,518.00
SECTION A TOTAL	$ 7,518.00

B. Metering

1. The express purpose of the metering system described in Section IV.B above is to measure generation output at the delivery point and does not serve to measure station service. Therefore all cost of metering shall be borne by the Developer.

SUBTOTAL (Material):	$15,000.00
SUBTOTAL (Labor):	$1,000.00
SECTION B TOTAL	$16,000.00

C. Primary Interconnection

1. Estimate for the installation of a new Viper recloser and control, the connection of the Viper to the 380 line and the UNH side riser pole, a line and source side VT for the Viper, and the relocation of existing switch 380J4. This estimate does not include the cable terminations on the riser pole underground 34.5 KV cables, the 34.5 KV underground cables themselves, or any equipment beyond the 34.5 KV underground cables.

SUBTOTAL	$	$107,500.00

2. Install the 651R control programming, and load check recloser and voltage blocking on the new Viper recloser at the 380 line tap.

SUBTOTAL	$	4,140.00

3. Installation and connection of a line VT, relay and control wiring for added reclosing permissives on breaker 0380 at Madbury.

SUBTOTAL	$	$32,256.00

4. PSNH Circuit Owner operations review and support of field efforts.

SUBTOTAL	$	1,000.00
SECTION C TOTAL	$	144,896.00

D. Telemetry and ESCC Integration

Labor (only) charges related to telemetry and administration at the ESCC.

Procedure updates
Enhancement Processing
Data Base/Display Updates
RTU hookup and checkout
Test and user verification
(Hardware by others)

SECTION D TOTAL	$	6,000.00
GRAND TOTAL (A + B + C + D)	**$**	**174,414.00**

VI. INTERCONNECTION EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

A. Delivery Point

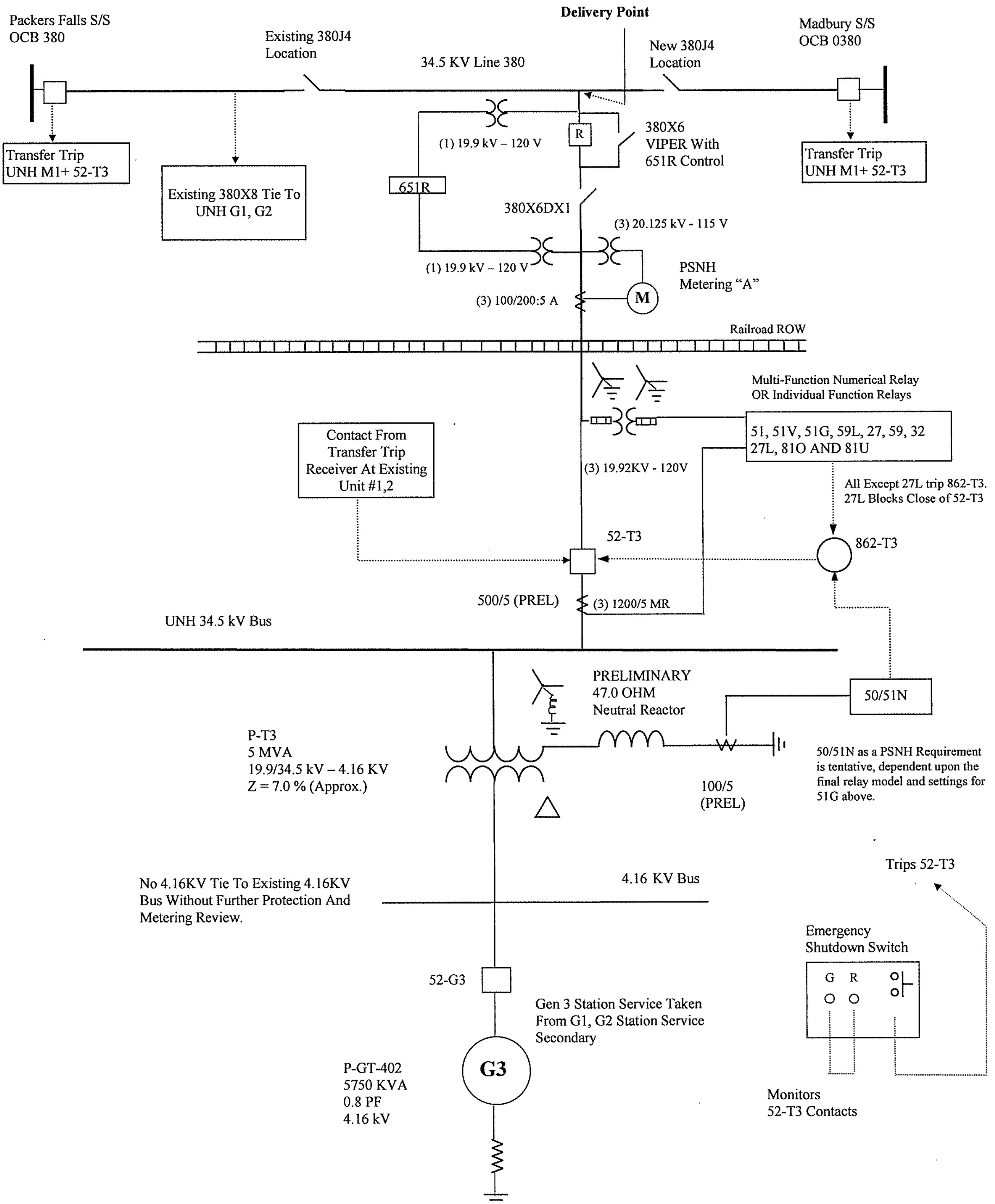
For the purpose of establishing ownership, operation and maintenance responsibilities, the location of facility energy delivery to PSNH (the "Delivery Point") must be defined. At this facility, the delivery point will be the tap of the 380 line on the PSNH side of the new 380X6 recloser.

B. Description of Responsibilities

PSNH will own and maintain all equipment up to the delivery point. Except for metering set "A", the Developer will own and maintain all equipment from the delivery point into and throughout the plant. PSNH will own metering set "A", to be maintained at the Developer's expense.

VII. DRAWINGS

Partial One-Line Diagram **SK-PCM-1080-2** is attached.



UNH SESD #1080
SK-PCM-1080-2
07/14/08

OPERATING AGREEMENT

FOR

PURPOSES OF WHEELING AND POWER SALES

AGREEMENT, dated , 200_ by and between The University of New Hampshire (hereinafter referred to as the "Interconnector"), and Public Service Company of New Hampshire, a New Hampshire corporation having its principal place of business in Manchester, New Hampshire (hereinafter referred to as "PSNH").

WHEREAS, Interconnector desires to interconnect their UNH Turbine electric generating facility (the "Facility"), (SESD #1080) located in Durham, New Hampshire, with the electric system of PSNH in accordance with applicable New Hampshire Public Utilities Commission ("NHPUC") Orders and federal law; and

WHEREAS, Interconnector intends to certify its generator as a Qualifying Facility ("QF") as defined by the Public Utilities Regulatory Policies Act ("PURPA") as it may be amended from time to time; and

WHEREAS, Interconnector desires to, and PSNH agrees to, provide for the interconnection of the Facility with the electric system of PSNH, its successors and permitted assigns, and Interconnector may have the right to sell the electric output of the Facility to PSNH and/or to such other third party purchasers with which Interconnector may make sales arrangements; and

WHEREAS, it is necessary that certain agreements be made prior to the interconnection of the Facility to ensure the safety, reliability and integrity of PSNH's electric system and the operation of the Facility; and

WHEREAS, Interconnector and PSNH wish to provide for certain other matters pertaining to discretionary power sales from the Facility;

NOW, THEREFORE, the parties hereby agree as follows:

Article 1. Interconnection and Voltage Characteristics.

The delivery point shall be that point at which the Facility interconnects with the 34.5 KV electric system of PSNH. Under this Agreement, the Interconnector shall receive and pay for the services necessary for the purpose of connecting the Facility with the PSNH electrical system, including Pool Transmission Facilities ("PTF") as defined by the New England Power Pool ("NEPOOL"), and non-PTF.

Unless PSNH converts its interconnection circuit, all electric energy delivered to PSNH's system from the Facility shall be 34.5 KV, three-phase, sixty hertz.

Article 2. Metering.

The metering shall be configured so as to represent the electric power output delivered to the PSNH electric system as specified in the Interconnection Report ("Report") dated July 14, 2008, attached as Attachment A. The metering may be installed on the generation side of the transformer provided that transformer losses are subtracted from the measured generation by a suitable method. Interconnector shall be responsible for all costs associated with the metering required for sales to PSNH and/or other third parties from the Facility.

Interconnector shall install and will own, and maintain all metering equipment as referenced in Article 5, to measure the physical flow of electrical energy from the Facility into the PSNH electric system. If at any time the meter is found to be in error by more than two percent fast or slow (+ or - 2%), Interconnector shall cause such meter to be corrected and the meter readings for the period of inaccuracy shall be adjusted to correct such inaccuracy so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the preceding month shall be made except by agreement of the parties. All tests and calibrations shall be made in accordance with New Hampshire Code of Administrative Rules, Chapter PUC 300 Rules and Regulations for Electric Service, as amended, and any applicable Rules and Regulations of ISO-New England ("ISO"). Interconnector is responsible for assuring that meter tests are performed as required at Interconnector's expense. The PSNH Meter Laboratory should be contacted in advance to arrange for said meter testing.

Interconnector shall cause the meter to be tested at any time upon request of either party and, at PSNH's option, in the presence of a representative of PSNH. If such equipment proves accurate within two percent fast or slow (+ or - 2%), the expense of the test shall be borne by the requesting party.

PSNH reserves the right to secure or seal the metering installation, but upon the written request of Interconnector will provide such information regarding, and access to, the metering installation as Interconnector requests. Interconnector is required to record electrical energy physically delivered to the PSNH electric system on an hour-by-hour basis, and to electronically make available to PSNH, Interconnector's generation in kilowatt-hours for each hour during the prior 24 hours.

To the extent necessary for Interconnector to receive credit and compensation for power sales to entities other than PSNH of electric energy and/or other power products generated at the Facility, PSNH shall cooperate with and assist Interconnector to ensure that the metering installations applicable to the Facility meet the required specifications and operational characteristics as necessary to accomplish such sales.

Article 3. Wheeling Arrangements.

If requested by Interconnector in connection with any sales of energy or other electric products to entities other than PSNH, PSNH (or other Northeast Utilities system companies) shall transmit the electric output of the Facility, or such portion(s) thereof as are identified by Interconnector, to an appropriate PTF point or to such purchasers (as applicable to the transaction) under the terms and conditions and rates set forth in the NORTHEAST UTILITIES SYSTEM COMPANIES Open Access Transmission Service Tariff No. 9 (the "NU OATT") filed with the Federal Energy Regulatory Commission ("FERC"), or its successor tariff, as those tariffs may be amended or supplemented from time to time hereafter. The wheeling of generation shall also be subject to any regulatory approved and applicable local transmission and distribution wheeling tariffs.

Article 4. Power Sales, Billing and Payment.

(a) PURPA Sales

This Agreement is contingent upon the Facility's continuing eligibility for status as a QF as defined by PURPA. As a QF, Interconnector may make sales to PSNH and PSNH shall purchase all or a portion of the electric energy and other electrical products generated at the Facility pursuant to the requirements of the PURPA, the New Hampshire Limited Electrical Energy Producers Act ("LEEPA"), and ISO.

Pursuant to PURPA, and as approved by the NHPUC in Docket No. DE 99-099, in accordance with the Settlement Agreement between PSNH and the State of New Hampshire, the rates paid to Interconnector for short-term, as available power sales to PSNH shall be the applicable market clearing price for such energy and/or other electrical product(s) or such replacement pricing methods as determined by the ISO or any successor entity for each period during which Interconnector has delivered such energy and/or other electrical power products for sale to PSNH. The above short-term prices shall be adjusted for line losses, wheeling costs, and administrative costs as they may be determined by PSNH or the NHPUC and as modified from time to time. The parties agree to abide by the ISO rules for recognition and determination of energy and capacity credit.

Facilities delivering all of their output to the PSNH grid will be assigned a Line Loss Adjustment Factor (the "LLAF"). The initial LLAF for the Facility is 1.0. If a recalculation of the LLAF is required, PSNH shall calculate a new LLAF to represent the change in PSNH's electrical system losses attributable to the generator characteristics and physical location of the Facility. The LLAF shall be applied to that portion of the generation output from the Facility which is sold to PSNH during a billing month by multiplying the LLAF times the kilowatt output. PSNH shall not have the right to use a new or materially different methodology for conducting any such LLAF study except as ordered by the NHPUC. The LLAF may be less than one or greater than one.

Should PSNH no longer be the load holding entity for the entire retail load connected to its System, the LLAF shall be proportionally reduced to reflect the percentage of retail load supplied by PSNH. This adjustment shall become effective with the billing months of February and August based upon the percentage of retail load supplied by PSNH over the previous six (6) month period ending in December and June, respectively. The LLAF may be recalculated at the request of either party. The requesting party shall pay for the cost of performing the line loss study. Upon the completion of the updated LLAF study, the new LLAF shall be used at the start of the next billing month.

In addition, Interconnector shall have the right and option at any time to engage a third party consultant to validate and verify the methodology and results of any LLAF study performed by PSNH under this Agreement, at Interconnector's expense. If the review performed by such consultant concludes that the results of any study performed by PSNH are incorrect, then PSNH shall perform a new study, at its expense, to determine the correct LLAF. Any dispute between the parties related to such studies shall be resolved by the NHPUC.

PSNH shall read the meter, installed in accordance with Article 2, once each month and shall promptly send Interconnector an invoice showing the billing month's net generation and amount owed for energy and other electrical products generated for any sales to PSNH hereunder. Interconnector shall then return to PSNH the approved invoice for payment. PSNH shall make payments to Interconnector electronically for the total amount due within 23 days of the meter reading date, provided that PSNH receives a timely return of the approved invoice.

Article 5. Interconnection and Protection Requirements.

Interconnector shall install or provide for the installation of all interconnection, protection, metering, and control equipment as specified in the Report to ensure the safe and reliable operation of the Facility in parallel with the PSNH system. The Interconnector will be responsible for all study costs associated with the development of the Report, and those costs associated with the equipment and its installation, required by the Report.

Up to the delivery point, all equipment shall be the sole property of Interconnector. Interconnector shall have sole responsibility for the operation, maintenance, replacement, and repair of the Facility, including the interconnection equipment owned by the Interconnector.

Prior to the interconnection to PSNH's system under this agreement, Interconnector shall have tested, and every twelve months thereafter, Interconnector shall test, or cause to be tested, all protection devices including verification of calibration and tripping functions; and Interconnector shall provide PSNH with a copy of the tests and results.

If either party reasonably determines that the operation or use of any portion of the protection system will or may not perform its protective function, Interconnector shall immediately open the interconnection between PSNH's system and the Facility. Interconnector shall promptly notify PSNH of this action and the reason for this action. The interconnection shall remain open until Interconnector has satisfactorily cured the defect. Any repair or replacement of Interconnector's equipment shall be at no cost to PSNH, except PSNH shall be responsible for any loss or damage requiring repair or replacement of all or a portion of the Interconnector's equipment as a result of the negligence or misconduct of PSNH, its agents or employees.

Article 6. Right of Access.

Upon prior written or oral notice to Interconnector, PSNH shall have the right to enter the property of Interconnector at mutually agreed upon reasonable times and shall be provided reasonable access to Interconnector's metering, protection, control, and interconnection equipment to review for compliance with this Agreement. PSNH shall provide Interconnector with a copy of any notes, reports or other documents made relating to any such inspection or review.

Article 7. Modification of Facility.

If Interconnector plans any modifications to its Facility as described in Attachment A, which modifications would reasonably be expected to affect its interconnection with the PSNH System, Interconnector shall give PSNH prior written notice of its intentions.

Article 8. Term of Agreement.

This Agreement shall become effective between the parties on the date of execution of this agreement but no earlier than the date PSNH receives notification from Interconnector that its status as a QF has been filed with FERC. This Agreement shall remain in full force and effect subject to the suspension and termination rights contained in this Article 8.

Interconnector may terminate this Agreement by giving PSNH not less than sixty (60) days prior written notice of its intention to terminate. PSNH may terminate the interconnection under this Agreement by giving not less than sixty (60) days prior written notice should Interconnector fail to substantially perform with the interconnection, metering and other safety provisions of this Agreement, and such failure continues for more than sixty (60) days from date of notice without cure. The PSNH notice shall state with specificity the facts constituting the alleged failure to perform by Interconnector. If the parties are unable to reach agreement within 60 days on a cure for the failure to perform, either party may elect to submit the dispute to the NHPUC for resolution.

If changes in applicable federal or state statutes, regulations or orders; or changes in applicable ISO or NEPOOL requirements occur which materially affect this Agreement, the parties shall negotiate in good faith to modify this Agreement to accommodate such changes. If the parties are unable to reach agreement within 60 days, either party may elect to submit the dispute to the

NHPUC for resolution.

PSNH may also terminate its obligation contained in this Agreement if all laws, regulations and orders mandating interconnections or purchases from qualifying facilities are repealed, or declared invalid by a Court or Regulatory Agency, and no revised law is enacted providing for such interconnection or sales on a similar basis.

After termination of this Agreement, both parties shall be discharged from all further obligation under the terms of this Agreement, excepting any liability (including without limitation the obligation to pay for power delivered prior to any such termination which obligation shall survive the termination of this Agreement) which may have been incurred before the date of such termination. Any reasonable costs incurred by PSNH to physically disconnect the Facility as a result of the termination of this Agreement shall be paid by the Interconnector. Termination of this Agreement shall not effect the parties' obligation to pay for power delivered prior to termination of that purchase obligation.

Article 9. Indemnification and Insurance.

Each party will be responsible for its equipment and the operation thereof and will indemnify and save the other harmless from any and all loss by reason of property damage, bodily injury, including death resulting there-from suffered by any person or persons including the parties hereto, employees thereof or members of the public, (and all expenses in connection therewith, including attorney's fees) whether arising in contract, warranty, tort (including negligence), strict liability or otherwise, caused by or sustained on, or alleged to be caused by or sustained on, equipment or property, or the operation or use thereof, owned or controlled by such party, except that each party shall be solely responsible for and shall bear all costs of its negligence, and willful misconduct, and claims by its own employees or contractors growing out of any workers' compensation law. The foregoing paragraph shall survive the termination of this Agreement and such termination will not extinguish any liabilities or obligations in respect of reimbursements under this paragraph, incurred up to the time of termination.

The Interconnector shall, at its own expense, continue to maintain throughout the term of this Agreement Comprehensive General Liability Insurance with a combined single limit of not less than $3,000,000 for each occurrence.

The insurance policy specified above shall name PSNH, Northeast Utilities and its subsidiaries, officers, directors and employees, as additional insured with respect to any and all third party bodily injury and/or property damage claims arising from Interconnector's performance of this Agreement. It is further agreed that PSNH shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance. The policy shall not be canceled, terminated, altered, reduced or materially changed without at least thirty (30) days prior written notice to PSNH.

Evidence of the required insurance shall be provided to PSNH in the form of a Certificate of Insurance prior to the actual physical interconnection of the Facility, and annually thereafter. During the term of this Agreement, the Interconnector, upon PSNH's reasonable request, shall furnish PSNH with certified copies of the actual insurance policies described in this Article.

The insurance coverage shall be primary and is not in excess to or contributing with any insurance or self-insurance maintained by PSNH or its affiliates and shall not be deemed to limit Interconnector's liability under this Agreement.

PSNH shall have the right to modify the limits of liability specified herein, at any time in the future, to remain consistent with those limits generally required by the NHPUC. PSNH must notify Interconnector in writing, at least ninety (90) days prior to any required change and these new liability limits will become effective upon renewal of the Insurance Policy.

In no event shall either party be liable, whether in contract, tort (including negligence), strict liability, warranty, or otherwise, for any special, indirect, incidental, punitive or consequential losses or damages, suffered by the other party or any person or entity and arising out of or related to this Agreement including but not limited to, cost of capital, cost of replacement power, loss of profits or revenues or the loss of the use thereof. This paragraph of Article 9 shall apply notwithstanding any other statement to the contrary, if any, in this Agreement and shall survive the termination of this Agreement.

Article 10. Force Majeure.

Neither party shall be considered to be in default hereunder and shall be excused from performance hereunder if and to the extent that it shall be prevented from doing so by storm, flood, lightning, earthquake, explosion, equipment failure, civil disturbance, labor dispute, act of God or the public enemy, action of a court or public authority, withdrawal of equipment from operation for necessary maintenance and repair, or any other cause beyond the reasonable control of either party and not due to the fault or negligence of the party claiming force majeure, provided that the party claiming excuse from performance uses its best efforts to remedy its inability to perform.

Article 11. Dispute Resolution and Voluntary Arbitration.

In the event of any dispute, disagreement, or claim (except for disputes referred to the NHPUC under Article 8 of this Agreement) arising out of or concerning this Agreement, the Party that believes there is such a dispute, disagreement, or claim will give written notice to the other Party of such dispute, disagreement, or claim. The affected Parties shall negotiate in good faith to resolve such dispute, disagreement, or claim. If such negotiations have not resulted in resolution of such dispute to the satisfaction of the affected Parties within ten (10) working days after notice of the dispute has been given, then, an affected Party may, upon mutual agreement of all of the affected Parties, submit such dispute, disagreement, or claim arising out of or concerning this Agreement, including whether such dispute, disagreement, or claim is arbitrable, to binding arbitration.

The arbitration proceeding shall be conducted by a single arbitrator, appointed by mutual agreement of the affected Parties, in Manchester, New Hampshire, under the Commercial Arbitration Rules of the American Arbitration Association in effect at the time a demand for arbitration under such rules was made. In the event that the affected Parties fail to agree upon a single arbitrator, each shall select one arbitrator, and the arbitrators so selected shall, within twenty (20) days of being selected, mutually select a single arbitrator to govern the arbitration. A decision and award of the arbitrator made under the Rules and within the scope of his or her jurisdiction shall be exclusive, final, and binding on all Parties, their successors, and assigns. The costs and expenses of the arbitration shall be allocated equitably amongst the affected Parties, as determined by the arbitrator(s). Judgment upon the award rendered by the arbitrator(s) may be entered in any court having jurisdiction. Each Party hereby consents and submits to the jurisdiction of the federal and state courts in the State of New Hampshire for the purpose of confirming any such award and entering judgment thereon.

Article 12. Modification of Agreement.

In order for any modification to this Agreement to be binding upon the parties, said modification must be in writing and signed by both parties.

Article 13. Prior Agreements Superseded.

Once effective, this Agreement with Attachment A represents the entire agreement between the parties with respect to the interconnection of the Facility with the PSNH electric system and, as between Interconnector and PSNH, all previous agreements including previous discussion, communications and correspondence related thereto are superseded by the execution of this Agreement.

Article 14. Waiver of Terms or Conditions.

The failure of either party to enforce or insist upon compliance with any of the terms or conditions of this Agreement shall not constitute a general waiver or relinquishment of any such terms or conditions, but the same shall remain at all times in full force and effect. Any waiver is only effective if given to the other party in writing.

Article 15. Binding Effect; Assignment

This Agreement shall be binding upon, and shall inure to the benefit of, the respective successors and permitted assigns of the parties hereto. PSNH shall not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of Interconnector except to a successor-in-interest. PSNH shall provide written notice to Interconnector of any such assignment to a successor-in-interest within fifteen (15) days following the effective date of the assignment. Interconnector shall have the right to assign this Agreement to any person or entity that is a successor-in-interest to the Facility without the consent of PSNH. In the event of any such assignment, Interconnector shall notify PSNH in writing within fifteen (15) days following the effective date of the assignment. Interconnector may make such other assignment of this Agreement as it determines, subject to the prior written consent of PSNH, which consent shall not be unreasonably withheld or delayed. Any assignment in violation of this Article shall be void at the option of the non-assigning party.

Article 16. Applicable Law.

This Agreement is made under the laws of the State of New Hampshire and, to the extent applicable, the Federal Power Act, and the interpretation and performance hereof shall be in accordance with and controlled by such laws, excluding any conflicts of law provisions of the State of New Hampshire that could require application of the laws of any other jurisdiction.

Article 17. Qualifying Facility Status

Interconnector has stated its intent to seek FERC certification of its generator as a QF and this Agreement and the related Interconnection Report shall be null and void should Interconnector fail to file for or should FERC deny the certification of QF status for the generator or later revoke the Project's QF status.

Article 18. Headings.

Captions and headings in the Agreement are for ease of reference and shall not be used to and do not affect the meaning of this Agreement.

Article 19. Notices and Service.

All notices, including communications and statements which are required or permitted under the terms of this Agreement, shall be in writing, except as otherwise provided or as reasonable under the circumstances. Service of a notice may be accomplished and will be deemed to have been received by the recipient party on the day of delivery if delivered by personal service, on the day of confirmed receipt if delivered by telegram, registered or certified commercial overnight courier, or registered or certified mail or on the day of transmission if sent by telecopy with evidence of receipt obtained, and in each case addressed as follows:

Interconnector:

Attn.:

Telephone No.
Fax No.
email:

PSNH:

Public Service Company of New Hampshire
780 North Commercial Street
P. O. Box 330
Manchester, NH 03105-0330
Attn.: Manager, Supplemental Energy Sources Department
Telephone No. (603) 634-2312
Fax No (603) 634-2449
email: psnhsesd@psnh.com

IN WITNESS WHEREOF, the parties, each by its duly authorized representative, have hereunto caused their names to be subscribed, as of the day and year first above written.

The University of New Hampshire

By: ____
Title: ____
Duly Authorized

Public Service Company of New Hampshire

____

By: John M. MacDonald
Title: Vice President - Energy Delivery & Generation
Duly Authorized

STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Draft Temporary Permit
Prevention of Significant Deterioration (PSD)
and
Non-Attainment New Source Review (NSR) Permit

Permit No: **TP-B-0531**
Date Issued: **May XX, 2007**

This certifies that:
University of New Hampshire
22 Colovos Road
Durham, New Hampshire 03824

has been granted a Temporary Permit and PSD/NSR Permit for the following facility and locations:

University of New Hampshire	**University of New Hampshire**
22 Colovos Road	**Rochester Neck Road**
Durham, New Hampshire 03824	**Rochester, New Hampshire 03839**

AFS Point Source Number (both locations) – 3301700009

New Hampshire has USEPA-approved procedures to ensure new construction or modifications of stationary sources do not violate control strategies or interfere with attainment or maintenance standards. These procedures authorize the DES to regulate significant increases for all criteria and regulated pollutants.

The joint PSD/NSR Temporary Permit is for a facility which emits air pollutants into the ambient air as set forth in equipment registration forms (ARD 1-6), filed with this Division under the date of **March 26, 2007** in accordance with RSA 125-C of the New Hampshire Laws. The PSD/NSR provisions of this permit are effective indefinitely or until such time that the facility applies and receives a Title V Operating Permit or a PSD/NSR Permit that modifies the terms and conditions of this permit. Request for permit renewal is due to the Division at least 90 days prior to expiration of this permit and must be accompanied by the appropriate permit application forms. This permit is valid upon issuance and expires on **[18 months from the month of permit issuance]**.

SEE ATTACHED SHEETS FOR ADDITIONAL PERMIT CONDITIONS

The owner or operator of the devices covered by this permit shall submit a written request for a permit amendment to the Director at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the devices covered by this permit which increases the amount of a specific air pollutant emitted by such devices or which results in the emission of any additional air pollutant. The change shall not take place until a new permit application is submitted and acted upon by the Director pursuant to Env-A 600.

Any permit deviation, which results in emissions greater than those stipulated in this permit, must be reported to the Division within 24 hours of the occurrence.

Robert R. Scott
Director, Air Resources Division

TABLE OF CONTENTS

ABBREVIATIONS

AAL	Ambient Air Limit
AP-42	Compilation of Air Pollutant Emission Factors
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BHP (or bhp)	Brake Horse Power
CAA	Clean Air Act, 42 U.S.C. § 7401, et seq.
CEMS (or CMS)	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
ERC	Emission Reduction Credit
g/bhp-hr	Grams per brake horsepower-hour
GCP	Good Combustion Practices
HAP	Hazardous Air Pollutant
HHV	High Heat Value
Hr	Hour
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
Lb/hr	Pounds per hour
LFG	Landfill Gas
LFGTE	Landfill Gas to Energy Project
LNB	Low NO_x Burner
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NHDES (or DES)	New Hampshire Department of Environmental Services
NMOC	Nonmethane Organic Compound
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmv	part per million by volume
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
SCFM	Standard Cubic Feet per Minute
SO_2	Sulfur Dioxide
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
UNH	University of New Hampshire
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

Facility Specific PSD & NSR Permit Conditions

I. Facility Description of Operations

The University of New Hampshire, Durham Campus (UNH) is an educational institution located in Durham, NH. The predominant sources of air pollutant emissions at UNH are their central heating plant, a boiler located at the New England Center, and emergency generators located throughout the university campus.

II. Project Description

UNH proposes to construct and operate a Landfill Gas to Energy (LFGTE) facility at the Turnkey Landfill located in Rochester, NH. Landfill gas (LFG) generated at the Turnkey Landfill will be treated and transferred by pipeline to the UNH cogeneration plant in Durham, which is located approximately twelve miles from the Turnkey Landfill. The LFGTE facility is considered a support facility to the UNH cogeneration plant and is therefore considered a modification to the existing UNH facility.

The five basic steps involved in the LFGTE facility will be: 1) gas preparation and sulfur removal; 2) electricity generation by two LFG fired engines; 3) LFG treatment and thermal oxidation of waste gas; 4) flaring of excess gas; and 5) product gas transfer to the cogeneration or supplemental turbine. The initial stage of processing consists of pressurizing the gas, lowering the gas temperature and removing moisture. The next step is to remove sulfur-bearing compounds known as total reduced sulfur compounds (TRS). At this point, the LFG required to operate the power generation equipment and thermal oxidizer is supplied. The remaining LFG is further compressed, additional moisture is removed, and it is treated to remove siloxanes and volatile organic compounds by use of activated carbon. Activated carbon is followed by pressure swing adsorption, which employs a molecular sieve to remove carbon dioxide.

The power generation equipment consists of two reciprocating engines designed to operate on LFG, each capable of generating 1,600 kW of electricity. The electricity will be used to produce power for the landfill gas treatment system described above.

The thermal oxidizer will destruct the waste gas streams produced during the regeneration of the activated carbon and the pressure swing adsorption's molecular sieve. The thermal oxidizer's maximum heat input is expected to be approximately 36 MMBtu/hr. Because of the variability of the energy content of the waste gas stream, LFG will be provided as a supplemental fuel for flame stabilization.

UNH has agreed to continuously take 7,000 standard cubic feet per minute (scfm) of LFG, regardless of the processing demand. UNH will install two open flares to be operated for supplemental and standby purposes. The supplemental flare will essentially operate continuously, at an average of 12% of its rated capacity. When the processing equipment and turbines are not operating, both of the flares will operate at their maximum rated capacity.

The amount of excess product gas will vary on a seasonal basis such that the greatest amount of excess gas will be available in the warmer months. In order to fully utilize the product gas, UNH has applied to install a supplemental turbine at the Durham campus cogeneration facility. UNH has not made a final decision regarding the installation of a turbine, but would like to permit the proposed unit should they decide to do so. The flare load described above is based on the assumption that the turbine will be installed. If the turbine is not installed, the quantity of gas flared will increase.

In summary, the pollutant emitting equipment which require permitting are two 1,600 kW LFG fired engines, one 36 MMBtu/hr thermal oxidizer, one 43.6 MMBtu/hr supplemental turbine, and two open flares rated at 125.4 MMBtu/hr and 105 MMBtu/hr.

The LFGTE project is classified as a major modification to an existing major source under both the federal New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. In the application, UNH proposed the following maximum emissions in tons per year (including emissions resulting from the operation of air pollution control equipment) from the LFGTE project:

Table 1: PSD and Non-Attainment NSR Applicability

Pollutant	Program	Projected Project Emissions tons per year (tpy)	Net Emissions Increase (tpy)	Significant Emissions Threshold (tpy)[1]	Is Proposed Modification Significant? (Yes/No)
NO_x	NSR	41.52	41.52	25	Yes
NO_2	PSD	41.52	41.52	40	Yes
CO	PSD	155.22	155.22	100	Yes
TSP/PM_{10}	PSD	23.14	23.14	25/15	No/Yes (Significant for PM_{10} only)
SO_2	PSD	24.52	24.52	40	No
VOC	NSR	48.24	48.24	25	No[2]
TRS/H_2S	PSD	0.69	0.69	10	No
Lead	PSD	<0.01	<0.01	0.6	No

1 The UNH campus is an existing major source of attainment pollutants for PSD applicability purposes and is a major source of NOx for NSR applicability purposes.

2 While the proposed VOC increase is above the 25 ton per year significant modification threshold, UNH is currently a minor source of VOC under the Non-Attainment NSR Program (VOC emissions are less than 50 tons per year) and therefore does not trigger Non-Attainment NSR for this project. However, this project will result in UNH becoming a new major source of VOC and future projects will be reviewed with respect to the 25 ton per year significant modification threshold.

III. Applicability of Federal Regulations

A. Federal Prevention of Significant Deterioration (PSD) Requirements

As shown above in Table 1, the LFGTE project will emit nitrogen dioxide (NO_2), a subset of NO_x, particulate matter less than 10 microns in diameter (PM_{10}), and CO in excess of major source PSD significant modification thresholds, and therefore is subject to PSD review and requires a PSD permit. The PSD regulations require that Best Available Control Technology (BACT) be applied to this project to minimize NO_2, PM_{10}, and CO emissions.

B. Federal Non-Attainment New Source Review (NSR) Requirements

As shown above in Table 1, the LFGTE project will emit NO_x in excess of major source NSR significant modification thresholds, and therefore is subject to NSR review and requires a NSR permit. The NSR regulations require that UNH install pollution control equipment for NO_x emissions capable of achieving the Lowest Achievable Emission Rate (LAER) for this pollutant. The NSR program also requires UNH to offset its NOx emissions at a ratio of 1.2:1, which requires UNH to obtain 50 tons of NOx emissions offsets (41.52 ton NOx increase * 1.2).

C. Federal New Source Performance Standards (NSPS) for Stationary Combustion Turbines

The Solar Mercury Combustion Turbine will be subject to the NSPS, 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines ("Subpart KKKK"). Subpart KKKK affects stationary combustion turbines with a design capacity greater than 10 MMBtu/hr constructed after February 18, 2005. The pollutants regulated under this NSPS are SO_2 and NOx.

IV. Air Quality Impact Analysis

As demonstrated by the air quality impact analysis and additional analyses required by state and federal regulations, including cavity analysis, toxic air pollutant impact assessment, and Class I impact analyses, the LFGTE project will not cause or contribute to violations of National Ambient Air Quality Standards (NAAQS), PSD increments, or Ambient Air Limits (AALs) as regulated under Env-A 1400.

V. Permitted Activities

In accordance with all of the applicable requirements identified in this permit, UNH is authorized to construct and operate the LFGTE project and all associated ancillary equipment and processes identified in Sections VI through VIII within the terms and conditions specified in this permit.

VI. Significant Activities Identification and Stack Criteria

A. Significant Activity Identification

The activities identified in Table 2 are subject to and regulated by this Permit:

Table 2: Emission Units to be Permitted

Device	Emission Unit Number	Manufacturer, Model, Serial Number	Maximum Operating Limitations
Reciprocating Engine #1	EU12	Caterpillar Model # G3520C Serial # TBD	1. Operation shall be limited to the combustion of landfill gas. 2. The maximum heat input shall be limited to 14.3 MMBTU/hr.

Table 2: Emission Units to be Permitted			
Device	**Emission Unit Number**	**Manufacturer, Model, Serial Number**	**Maximum Operating Limitations**
Reciprocating Engine #2	EU13	Caterpillar Model # G3520C Serial # TBD	1. Operation shall be limited to the combustion of landfill gas. 2. The maximum heat input shall be limited to 14.3 MMBTU/hr.
Supplemental Utility Flare	EU14	John Zink Co. Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of landfill gas. 2. The maximum heat input shall be limited to 125.4 MMBTU/hr.
Standby Utility Flare	EU15	John Zink Co. Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of landfill gas. 2. The maximum heat input shall be limited to 105.06 MMBTU/hr.
Thermal Oxidizer	EU16	Manufacturer TBD Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of landfill gas and waste gas produced from the regeneration of treatment media. 2. The maximum heat input shall be limited to 36 MMBTU/hr.
Solar Mercury Recuperative Turbine	EU17	Solar Model # Mercury 50-6000R Serial # TBD	1. Operation shall be limited to the combustion of landfill gas. 2. The maximum heat input shall be limited to 43.6 MMBTU/hr.

B. **Stack Criteria**

The stacks listed in Table 3 shall discharge vertically without obstruction (including rain caps) and meet the following criteria:

Table 3 – Stack Criteria				
Stack Number	**Emission Unit Number**	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (Feet)**	**Maximum Inside Stack Diameter (Feet)**
ST12	**EU12**	Reciprocating Engine #1	32	1.3
ST13	**EU13**	Reciprocating Engine #2	32	1.3
ST14	**EU14**	Supplemental Utility Flare	61.2	6.5
ST15	**EU15**	Standby Utility Flare	58.6	5.9
ST16	**EU16**	Thermal Oxidizer	30	4

Table 3 – Stack Criteria				
Stack Number	**Emission Unit Number**	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (Feet)**	**Maximum Inside Stack Diameter (Feet)**
ST17	**EU17**	Solar Mercury Recuperative Turbine	100	4.1

Changes to the state-only requirements pertaining to stack parameters (set forth in this permit), shall be permitted only when an air quality impact analysis which meets the criteria of Env-A 606 is performed either by the facility or the New Hampshire Department of Environmental Services, Air Resources Division (if requested by facility in writing) in accordance with the "DES-ARD Procedure for Air Quality Impact Modeling." All air modeling data shall be kept on file at the facility for review by DES upon request.

VII. Pollution Control Equipment/Method Identification

The device identified in Table 4 is considered pollution control equipment for each identified emissions unit:

Table 4 – Pollution Control Equipment/Method Identification			
Pollution Control Equipment Number	**Emission Unit Controlled**	**Description of Equipment/Method**	**Primary Pollutants Controlled**
PC1	LFG Treatment System	Thermal Oxidizer	Waste gases generated from LFG treatment system (siloxanes, VOCs)
PC2	SulfaTreat System	Sulfur removal through reaction with iron to form iron suflide	Sulfur in LFG
PC3	Molecular Sieve	Carbon dioxide removal via molecul r sieve	Carbon Dioxide

VIII. Applicable Requirements

A. Operational and Emission Limitations

1. The owner or operator shall be subject to the operational and emission limitations identified in Table 5 below.

Table 5 – Summary of Emission Limitations[3]							
Pollutant	**EU12 Reciprocating Engine #1**	**EU13 Reciprocating Engine #2**	**EU14 Supplemental Utility Flare**	**EU15 Standby Utility Flare**	**EU16 Thermal Oxidizer**	**EU17 Supplemental Turbine**	**Regulatory Citation**
NOx limit	0.5 g/bhp-hr (BACT/LAER) 2.5 g/bhp-hr (NOx RACT limit – one-hour average)	0.5 g/bhp-hr (BACT/LAER) 2.5 g/bhp-hr (NOx RACT limit – one-hour average)	0.060 lb/MMBtu (BACT/LAER)	0.060 lb/MMBtu (BACT/LAER)	0.065 lb/MMBtu (BACT/LAER)	(5 ppm @15% O_2) (BACT/LAER) 25 ppm @15% O_2[4] (NOx RACT limit)	Env-A 618.03(a) (LAER) Env-A 619.03(a) 40 CFR 52.21 (BACT)
NOx limit for multiple devices	20.92 tons per consecutive 12 month period for Reciprocating Engines #1and #2 (EU12 & EU13) combined.		8.12 tons per consecutive 12 month period for the Supplemental and Standby Utility Flares (EU14 & EU15) combined.		9.31 tons per consecutive 12 month period.	3.17 tons per consecutive 12 month period.	
NOx Control Technology							
CO limit	2.75 g/bhp-hr (BACT)	2.75 g/bhp-hr (BACT)	0.20 lb/MMBtu (BACT)	0.20 lb/MMBtu (BACT)	0.065 lb/MMBtu (BACT)	0.022 lb/MMBtu (10 ppm @15% O2) (BACT)	Env-A 619.03(a) 40 CFR 52.21 (BACT)
CO limit for multiple devices	115.03 tons per consecutive 12 month period for Reciprocating Engines #1and #2 (EU12 & EU13) combined.		27.07 tons per consecutive 12 month period for the Supplemental and Standby Utility Flares (EU14 & EU15) combined.		9.31 tons per consecutive 12 month period.	3.80 tons per consecutive 12 month period.	
CO Control Technology							
SO_2 limit	0.046 g/bhp-hr	0.046 g/bhp-hr	0.149 lb/MMBtu	0.149 lb/MMBtu	0.015 lb/MMBtu	0.001 lb/MMBtu	Env-A 604.01
SO_2 limit for multiple devices	1.94 tons per consecutive 12 month period for Reciprocating Engines #1and #2 (EU12 & EU13) combined.		20.17 tons per consecutive 12 month period for the Supplemental and Standby Utility Flares (EU14 & EU15) combined.		2.15 tons per consecutive 12 month period.	0.26 tons per consecutive 12 month period.	
SO_2 Control Technology							

3 The emissions limitations contained in Table 5 above are based on a 3-hour averaging period unless otherwise specified.

4 The NOx limit of 25 ppm @15% O_2 is based on the NOx RACT standard contained in Env-A 1211.06 and is more stringent than the NSPS limit of 96 ppm @15% O_2. Since both standards are based on a 1-hour averaging period, only the more stringent limit is included for streamlining purposes.

Table 5 – Summary of Emission Limitations[3]

Pollutant	EU12 Reciprocating Engine #1	EU13 Reciprocating Engine #2	EU14 Supplemental Utility Flare	EU15 Standby Utility Flare	EU16 Thermal Oxidizer	EU17 Supplemental Turbine	Regulatory Citation
TSP/PM10 limit[5]	0.10 g/bhp-hr (BACT)	0.10 g/bhp-hr (BACT)	0.042 lb/MMBtu (BACT)	0.042 lb/MMBtu (BACT)	0.042 lb/MMBtu (BACT)	0.042 lb/MMBtu (BACT)	Env-A 619.03(a) 40 CFR 52.21 (BACT)
TSP/PM10 limit for multiple devices	4.18 tons per consecutive 12 month period for Reciprocating Engines #1and #2 (EU12 & EU13) combined.		5.68 tons per consecutive 12 month period for the Supplemental and Standby Utility Flares (EU14 & EU15) combined.		6.02 tons per consecutive 12 month period.	7.25 tons per consecutive 12 month period.	
TSP/PM10 Control Technology							
VOC limit	0.70 g/bhp-hr	0.70 g/bhp-hr	0.060 lb/MMBtu	0.060 lb/MMBtu	0.060 lb/MMBtu	0.013 lb/MMBtu	Env-A 604.01
VOC limit for multiple devices	29.28 tons per consecutive 12 month period for Reciprocating Engines #1and #2 (EU12 & EU13) combined.		8.12 tons per consecutive 12 month period for the Supplemental and Standby Utility Flares (EU14 & EU15) combined.		8.60 tons per consecutive 12 month period.	2.24 tons per consecutive 12 month period.	
VOC Control Technology							

5 Both the TSP and PM10 emission limits are based on filterable particulate matter only. The TSP and PM10 limits will be re-evaluated once condensable particulate matter emissions are determined during the initial compliance stack testing.

2. The owner or operator shall be subject to the operational and emission limitations identified in Table 6 below.

Table 6: Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
1.	*Facility-Wide HAP Emission Limitation* Facility-wide emissions of Hazardous Air Pollutants (HAPs, as defined in Section 112 of the 1990 Clean Air Act Amendments) shall be limited to less than 10 tpy for any individual HAP and 25 tpy for all HAPs combined.	Facility Wide	Env-A 604.02(a)(1)
2.	*24-hour and Annual Ambient Air Limit* The emissions of any Regulated Toxic Air Pollutant (RTAP) shall not cause an exceedance of its associated 24-hour or annual Ambient Air Limit (AAL) as set forth in Env-A 1450.01, *Table Containing the List Naming All Regulated Toxic Air Pollutants*.	Facility Wide	Env-A 1400
3.	*Revisions of the List of RTAPs* In accordance with RSA 125-I:5 IV, if DES revises the list of RTAPs or their respective AALs or classifications under RSA 125-I:4, II and III, and as a result of such revision The owner or operator is required to obtain or modify the permit under the provisions of RSA 125-I or RSA 125-C, The owner or operator shall have 90 days following publication of notice of such final revision in the New Hampshire Rulemaking Register to file a complete application for such permit or permit modification.	Facility Wide	RSA 125-I:5 IV
4.	*Visible Emission Standard for Fuel Burning Devices Installed After May 13, 1970* The average opacity from fuel burning devices installed after May 13, 1970 shall not exceed 20 percent for any continuous 6-minute period.	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 2002.02
5.	*Activities Exempt from Visible Emission Standards* The average opacity shall be allowed to be in excess of those standards specified in Env-A 2002.02 for one period of 6 continuous minutes in any 60 minute period during startup, shutdown, or malfunction.	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 2002.04(c)
6.	*Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985* The particulate matter emissions from fuel burning devices installed on or after January 1, 1985 shall not exceed 0.30 lb/MMBtu.	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 2002.08
7.	*NOx RACT Emission Standard for Combustion Turbine* On and after November 1, 2002, all gas-fired turbines constructed after May 27, 1999, shall be limited to an hourly average NOx RACT emission limit of 25 ppmvd, corrected to 15% O2, or 0.092 lb. per million Btu, when operating on gas.	EU17	Env-A 1211.06(d)

Table 6: Operating and Emission Limitations			
Item #	Requirement	Applicable Emission Unit	Regulatory Citation
8.	*<u>NOx Emissions Standard for Stationary Combustion Turbines Subject to 40 CFR Part 60 Subpart KKKK</u>* NOx emissions from the Solar Mercury Recuperative Turbine shall be limited to 96 ppm at 15% O_2 or 5.5 lb per MWh of useful energy output[6].	EU17	40 CFR § 60.4320
9.	*<u>SO_2 Emissions Standard for Stationary Combustion Turbines Subject to 40 CFR Part 60 Subpart KKKK</u>* a. SO_2 emissions from the Solar Mercury Recuperative Turbine shall be limited to 0.90 pounds per megawatt-hour (lb/MWh) gross output. b. As an alternative to item (a) above, The owner or operator may comply with this part by burning fuel containing total potential sulfur emissions less than or equal to 0.060 lb SO_2/MMBtu heat input.	EU17	40 CFR § 60.4330
10.	The owner or operator must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	EU17	40 CFR § 60.4333(a)
11.	<u>Pollution Control Equipment Operation and Maintenance:</u> a. The combustion chamber shall be maintained at a minimum temperature of 1,280°F, based on an hourly average; and b. The thermal oxidizer shall be maintained in accordance with manufacturer's recommendations.	EU16	Env-A 604.01
12.	Flares shall be operated with a flame present at all times when landfill gas is delivered to the flares.	EU14 EU15	Env-A 604.01

6 The NOx limit of 25 ppm @15% O_2 is based on the NOx RACT standard contained in Env-A 1211.06 and is more stringent than the NSPS limit of 96 ppm @15% O_2.

<table>
<tr><th colspan="4">Table 6: Operating and Emission Limitations</th></tr>
<tr><th>Item #</th><th>Requirement</th><th>Applicable Emission Unit</th><th>Regulatory Citation</th></tr>
<tr><td>13.</td><td>a. Reciprocating Engines #1 and #2 shall comply with the following emission limitations:
<table>
<tr><th colspan="4">Emission Limitations for EU12 and EU13</th></tr>
<tr><th>Pollutant</th><th>Emission Limitation</th><th>Averaging Time</th><th>Control Technology</th></tr>
<tr><td>SO_2</td><td>0.046 g/bhp-hr</td><td>3-hour rolling</td><td>N/A</td></tr>
<tr><td>CO</td><td>2.75 g/bhp-hr</td><td>3-hour rolling</td><td>Lean Burn Technology BACT</td></tr>
<tr><td>TSP/PM_{10}</td><td>0.10 g/bhp-hr</td><td>3-hour rolling</td><td>Low Sulfur Fuels BACT</td></tr>
<tr><td>NOx</td><td>0.5 g/bhp-hr</td><td>3-hour rolling</td><td>Lean Burn Technology LAER & BACT</td></tr>
<tr><td>VOCs</td><td>0.70 g/bhp-hr</td><td>3-hour rolling</td><td>N/A</td></tr>
</table>
b. The emissions limitations in (a) above shall apply at all times.</td><td>EU12
EU13</td><td>Env-A 618
Env-A 619
40 CFR 52.21
40 CFR 51.165</td></tr>
<tr><td>14.</td><td>a. The Supplemental and Standby Utility Flares shall comply with the following emission limitations:
<table>
<tr><th colspan="4">Emission Limitations for EU14 and EU15</th></tr>
<tr><th>Pollutant</th><th>Emission Limitation</th><th>Averaging Time</th><th>Control Technology</th></tr>
<tr><td>SO_2</td><td>0.149 lb/MMBtu</td><td>3-hour rolling</td><td>N/A</td></tr>
<tr><td>CO</td><td>0.20 lb/MMBtu</td><td>3-hour rolling</td><td>BACT</td></tr>
<tr><td>TSP/PM_{10}</td><td>0.042 lb/MMBtu</td><td>3-hour rolling</td><td>BACT</td></tr>
<tr><td>NOx</td><td>0.060 lb/MMBtu</td><td>3-hour rolling</td><td>LAER & BACT</td></tr>
<tr><td>VOCs</td><td>0.060 lb/MMBtu</td><td>3-hour rolling</td><td>N/A</td></tr>
</table></td><td>EU14
EU15</td><td>Env-A 618
Env-A 619
40 CFR 52.21
40 CFR 51.165</td></tr>
</table>

B. **<u>Initial Compliance Demonstration Requirements</u>**

The owner or operator shall demonstrate initial compliance with the conditions specified in Tables 5 and 6 no later than 180 days after startup of the new affected source. The owner or operator shall perform the monitoring and/or testing indicated in Table 7 below:

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	EU12	NOx	a. Pursuant to Env-A 802, the owner or	Within 60 days	Env-A 801.02

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
	EU13 EU16 EU17	CO SO_2 TSP PM10 VOC	operator shall conduct initial performance tests for SO_2, NO_x, CO, TSP, PM_{10} & opacity to demonstrate compliance with the respective emissions limitations in Tables 5 and 6. b. The following test methods or Division approved alternatives shall be used for the pollutants specified: i. Method 1 or 2 to determine exit velocity of stack gases; ii. Method 3 or 3A to determine carbon dioxide, oxygen, excess air, and molecular weight (dry basis) of stack gases; iii. Method 4 to determine moisture content (volume fraction of water vapor) of stack gases; iv. Methods 5, 201A, and 202 for total suspended particulate matter, filterable PM_{10}, and condensable PM_{10}[7]; v. Methods 6 or 6C for sulfur dioxide; vi. Method 7 for NOx; vii. Method 9 for opacity; viii. Method 10 for CO; and ix. Method 25 or 25A for total gaseous non-methane organic compound emissions.	after achieving the maximum production rate, but not later than 180 days after initial startup of such facility	
2.	EU14 EU15	NOx, CO, VOC	a. The owner or operator must conduct an initial performance test for NOx and CO for the flares. b. Testing shall be conducted in accordance with the methods specified in item (1) above of this table.	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility	Env-A 801.02
3.	EU12 EU13 EU14 EU15 EU16 EU17	NOx CO SO_2 TSP PM10 VOC	Stack Testing Requirements: a. A compliance stack emissions test shall conform to the following: i. The general requirements of 40 CFR 60.8(a), (b), (d), (e), and (f); and ii. The test methods contained in 40 CFR	For each required stack test	Env-A 802.02

7 Both the TSP and PM10 emission limits in this permit are based on filterable particulate matter only. The TSP and PM10 limits will be re-evaluated once condensable particulate matter emissions are determined during the initial compliance stack testing.

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			60, Appendix A, 40 CFR 51, Appendix M, or any other USEPA-promulgated stack test method. b. An owner or operator shall sample emissions at locations and sampling points that will provide representative measurements of the actual emissions during source operation at the time of the test. c. The owner or operator shall perform a stratification check at each measurement location where a determination of a gas concentration is required. d. A stratification check shall be accomplished by measuring the pollutant or diluent, oxygen or carbon dioxide gas concentration in accordance with the USEPA Emission Measurement Technical Information Center Guideline Document, GD-025, Determination of the Presence of Stratification of Gaseous Pollutant and Diluent Emissions for Continuous Emission Monitor or Reference Method Relative Accuracy Locations, June 21, 1994. e. If stratification does not exist, a single point gas/diluent measurement location shall be acceptable within the inner 50 percent area of the duct or stack cross section. f. If stratification exists, The owner or operator shall obtain samples either at locations across the stack diameter equivalent to those specified in 40 CFR 60, Appendix B, Performance Specification 2, paragraph 3.2, or the locations specified in 40 CFR 60, Appendix A, Method 1.		
4.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	Pre-test Notice: a. At least 30 days prior to the commencement of source testing, the owner or operator shall notify the division of the date(s) of any planned compliance stack testing. b. The division shall require the rescheduling of any compliance stack emissions test if the staff necessary to observe the test are not available.	At least 30 days prior to planned compliance testing	Env-A 802.03

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
5.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	Pre-Test Protocol: At least 30 days prior to the commencement of source testing, The owner or operator shall submit to the division a pre-test protocol with the following information: a. The facility name, address, telephone number, and contact; b. The name of the contractor testing company, company contact, and telephone number; c. The reasons for performing the compliance stack test; d. A complete test program description; e. A description of the process or device to be tested; f. A description of the operational mode of the process during the testing period; g. A list of operational and process data to be collected; h. A list of test methods to be used; i. A description of any requested alternatives or deviations from standard USEPA testing methods or from the requirements of this part; j. a list of calibration methods and sample data sheets; k. a description of pre-test preparation procedures; l. a list of sample collection and analysis methods; m. a description of quality assurance procedures specific to the testing; n. a description of standard operating procedures (SOPs) for laboratory analysis of samples, or reference to SOPs already on file with the division; and o. A description of facility safety/ emergency response procedures applicable to the area of the facility in which the test will occur.	At least 30 days prior to commencement of compliance testing	Env-A 802.04
6.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	Pre-test Meeting: a. At least 15 days prior to the test date, The owner or operator and any contractor retained by The owner or operator to conduct the test shall meet with a division representative in person or over the telephone.	At least 15 days prior to the test date	Env-A 802.05

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			b. The details of the test, the testing schedule, and the process conditions under which the data shall be collected, shall be finalized at the pre-test meeting. c. A pre-test meeting may be held less than 15 days prior to the test date so long as implementation of any testing or operational changes resulting from the meeting can be carried out prior to the scheduled test date and the scheduled test integrity is not jeopardized.		
7.	EU12 EU13 EU14 EU15 EU16 EU17	Repeating a compliance stack test	Repeating a Compliance Stack Test: An owner or operator that repeats a compliance stack test on the same source shall not be required to submit another pre-test protocol or attend another pre-test meeting as specified in Env-A 802.04 and Env-A 802.05, provided that the following conditions are met: a. The owner or operator uses the same stack testing contractor; b. The owner or operator follows all stack test and plant operating conditions specified in the previously accepted pre-test protocol or any deviations from the previously accepted pre-test protocol are specified in detail in the letter described in (d) below; c. the division approved the previous stack test as submitted by The owner or operator and the stack testing contractor; and d. the owner, operator, or stack testing contractor submits a letter to the division referencing the previously approved pre-test protocol and pre-test meeting and identifying in detail any deviations from the previously accepted pre-test protocol or pre-test meeting.	When a stack test must be repeated	Env-A 802.06
8.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	Scheduling Changes: a. The owner or operator shall notify the division by telephone, fax, or electronic mail prior to any changes in the testing schedule for a compliance stack test. b. The owner or operator shall obtain prior approval from the division, which shall be based on staff availability, of any	As necessary	Env-A 802.07

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			new date for a compliance stack test.		
9.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	<u>Calibration Data for Stack Sampling Equipment</u>: a. The owner or operator shall provide calibration data for any sampling equipment used during the compliance stack testing to the division upon request during the day of testing. b. The owner or operator shall provide copies of all calibration and field test data taken during the testing, including failed runs, to the division upon request.	Upon request by DES	Env-A 802.08
10.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	<u>Alternative Testing Methods During a Test</u>: The division shall approve deviations from the agreed-upon test method or pre-test protocol if the following criteria are met: a. The owner or operator informs division personnel assigned to the stack test of the following: i. The deviation from the testing method or planned operational mode of the source; ii. The reason(s) for the deviation; and iii. The implications of such a deviation; and b. The owner or operator provides technical justification showing that allowance of such deviation will not affect the accuracy of the compliance stack emissions test.	Upon approval by DES	Env-A 802.09
11.	EU12 EU13 EU14 EU15 EU16 EU17	Initial Performance Test	<u>Operating Conditions During a Stack Emissions Test</u>: A compliance test shall be conducted under one of the following operating conditions: a. Between 90 and 100 percent, inclusive, of maximum production rate or rated capacity; b. A production rate at which maximum emissions occur; or c. At such operating conditions agreed upon during a pre-test meeting conducted pursuant to Env-A 802.05.	For each performance test	Env-A 802.10
12.	EU12	Initial	<u>Report Submission Requirements</u>:	For each	Env-A 802.11

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
	EU13 EU14 EU15 EU16 EU17	Performance Test	a. Except as provided in (b) below, the owner or operator shall submit a report to the division documenting the results of the compliance stack emissions test no more than 60 days after completion of testing. b. When conducting a quality assurance/quality control audit in accordance with Env-A 808, the owner or operator of the source shall submit a report to the division documenting those results in accordance with Env-A 808.07(b). c. The compliance stack emissions test report shall contain the following information: i. All the information required for the pre-test protocol as described in Env-A 802.04; ii. All test data; iii. All calibration data; iv. Process data agreed by the division and The owner or operator to be collected; v. All test results; vi. A description of any discrepancies or problems that occurred during testing or sample analysis; vii. An explanation of how discrepancies or problems were treated and their effect on the final results; and viii. A list and description of all equations used in the test report, including sample calculations for each equation used.	performance test	
13.	EU12 EU13 EU17	NOx	<u>Compliance Stack Testing for NOx RACT</u>: a. The owner or operator shall conduct an initial compliance stack test in accordance with Env-A 802 to demonstrate compliance with the NOx RACT emission limits contained in Env-A 1211.06 and Env-A 1211.07. b. The following test methods shall be used as applicable: i. Method 7, 7A, 7C, 7D or 7E as described in 40 CFR 60, Appendix	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility. Subsequent testing every 3 years after date	Env-A 803.02

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			A, to determine NOx concentrations in stack gases; ii. Method 10 as described in 40 CFR 60, Appendix A, to determine carbon monoxide concentrations in stack gases; iii. Methods 1 and 2, 2C, 2F, 2G, or 2H, as described in 40 CFR 60, Appendix A, to determine the exit flow rate of stack gases; iv. Method 3 or 3A as described in 40 CFR 60, Appendix A, to determine carbon dioxide, oxygen, excess air and molecular weight, dry basis, of stack gases; and v. Method 4 as described in 40 CFR 60, Appendix A, to determine the volume fraction of water vapor in stack gases. c. The owner or operator may use Method 20 as described in 40 CFR 60, Appendix A, in lieu of the methods identified in (b) above, to determine NOx concentrations in stationary gas turbine stack gases.	of initial test.	
40 CFR 60 Subpart KKKK Initial Performance Testing Requirements:					
14.	EU17	NOx and SO_2	The owner or operator shall conduct an initial performance test in accordance with 40 CFR §60.8 and 40 CFR §60.4400.	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility.	40 CFR §60.8(a)
15.	EU17	NOx and SO_2	The owner or operator shall provide the Administrator and DES at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator and DES the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, The owner or operator of an affected facility shall notify the	At least 30 days prior to performance test, except as noted.	40 CFR §60.8(d)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			Administrator and DES as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator and DES by mutual agreement.		
16.	EU17	NOx and SO_2	The owner or operator shall provide, or cause to be provided, performance testing facilities as follows: a. Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures. b. Safe sampling platform(s). c. Safe access to sampling platform(s). d. Utilities for sampling and testing equipment.	For each performance test.	40 CFR §60.8(e)
17.	EU17	NOx and SO_2	Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in 40 CFR Part 60 Subpart KKKK. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.	For each performance test.	40 CFR §60.8(f)
18.	EU17	NOx	There are two general methodologies that the owner or operator may use to conduct the performance tests. For each test run: a. Measure the NO_X concentration (in parts per million (ppm)), using USEPA	During initial performance test	40 CFR §60.4400(a)(1)

Table 7 – Initial Performance Testing Requirements					
Item No.	Applicable Emission Unit(s)	Pollutant/ Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			Method 7E or USEPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using USEPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate: $E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P}$ (Eq. 5) Where: E = NO_X emission rate, in lb/MWh 1.194×10^{-7} = conversion constant, in lb/dscf-ppm $(NO_X)_c$ = average NO_X concentration for the run, in ppm Q_{std} = stack gas volumetric flow rate, in dscf/hr P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or		
			b. Measure the NO_X and diluent gas concentrations, using either USEPA Methods 7E and 3A, or USEPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use USEPA Method 19 in appendix A of this part to calculate the NO_X emission		

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.		
19.	EU17	NOx	Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following USEPA Method 20 or USEPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.	During initial performance test	40 CFR § 60.4400(a)(2)
20.	EU17	NOx	Notwithstanding the preceding condition in this table (40 CFR § 60.4400(a)(2)), the owner or operator may test at fewer points than are specified in USEPA Method 1 or USEPA Method 20 in appendix A of this part if the following conditions are met: a. The owner or operator may perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) of appendix A of 40 CFR Part 75. b. Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test: i. If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then the owner or operator may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8	During initial performance test	40 CFR § 60.4400(a)(3)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or ii. For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, the owner or operator may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or iii. For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, the owner or operator may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.		
21.	EU17	NOx	The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The owner or operator may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The owner or operator must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes. a. If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance	During initial performance test	40 CFR § 60.4400(b)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			testing is required for each fuel. b. For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the owner or operator must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test. c. If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with 40 CFR §60.4335, then that monitoring system must be operated concurrently with each USEPA Method 20 or USEPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable 40 CFR §60.4320 NO_X emission limit. d. Compliance with the applicable emission limit in 40 CFR §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR §60.4320. e. If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR §60.4405) as part of the initial performance test of the affected unit. f. The ambient temperature must be greater than 0 °F during the performance test.		
22.	EU17	NOx	If the owner or operator has chosen to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls in accordance with 40 CFR §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected	During initial performance test	40 CFR § 60.4410

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			unit, as specified in 40 CFR §60.4355.		
23.	EU17	SO_2	The owner or operator must conduct an initial performance test for SO_2, as required in 40 CFR §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that may be used to conduct the performance tests. a. Method 1: If The owner or operator chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels. The fuel analyses of this section may be performed either by the owner/operator, a service contractor retained by the owner/operator, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using (for gaseous fuels) ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17). b. Method 2: Measure the SO_2 concentration (in ppm), using USEPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of USEPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using USEPA Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the	During initial performance test	40 CFR §60.4415(a) 40 CFR §60.8

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			SO_2 emission rate: $$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad \text{(Eq. 6)}$$ Where: E = SO_2 emission rate, in lb/MWh 1.664×10^{-7} = conversion constant, in lb/dscf-ppm $(SO_2)_c$ = average SO_2 concentration for the run, in ppm Q_{std} = stack gas volumetric flow rate, in dscf/hr P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR §60.4350(f)(2); or c. Method 3: Measure the SO_2 and diluent gas concentrations, using either USEPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use USEPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR §60.4350(f) to calculate the		

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			SO_2 emission rate in lb/MWh.		

C. **Monitoring/Testing Requirements**

The owner or operator is subject to the monitoring/testing requirements as contained in Table 8 below:

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	EU12 EU13 EU14 EU15 EU16	Sulfur content of gaseous fuel (landfill gas)	For the purpose of determining the sulfur content in grains of sulfur per 100 cubic feet of natural gas, the owner or operator shall use one of the following test methods: a. ASTM D 1072-90; b. ASTM D 4084-94; c. ASTM D 3246-96; d. ASTM D 5504-01; or e. ASTM D 6228-98.	In accordance with the monitoring schedules specified in items (22) and (23) below of this table	Env-A 806.03(a)
2.	EU12 EU13 EU16 EU17	Opacity	Opacity Measurements: a. The owner or operator shall conduct opacity measurements following the procedures set forth in 40 CFR 60 Appendix A, Method 9, *Visual Determination of the Opacity of Emissions from Stationary Sources.* b. The measurements in (a) above shall be taken over 60 minutes during normal operations of the device.	Upon request by DES or USEPA or as determined necessary by the owner or operator	Env-A 807.02
3.	EU 14 EU15	Opacity	Opacity Measurements: a. The owner or operator shall conduct measurements of the amount of time that any visible fugitive emissions occur during an observation period by following 40 CFR 60, Appendix A, Method 22 – *Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares.* b. The observation period for (a) above is 2 hours and shall be used according to Method 22	Upon request by DES or USEPA or as determined necessary by the owner or operator	Env-A 807.05
4.	EU17	NOx CEM	The owner or operator of a stationary source shall install, operate, maintain, and perform quality assurance testing of a CEM system meeting all of the requirements specified in	Continuously	Env-A 808.02

Table 8 – Monitoring and Testing Requirements					
Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			Env-A 808.		
5.	EU17	NOx CEM	Minimum Specifications for CEM Systems: The CEM system shall meet the following minimum specifications: a. A CEM system for measuring gaseous emissions shall average and record the data for each calendar hour; b. All CEM systems shall: i. Include a means to display instantaneous values of gaseous emission concentrations; and ii. Complete a minimum of one cycle of operation, which shall include measurement, analyzing, and data recording for each successive 5-minute period for systems measuring gaseous emissions, unless a longer time period is approved in accordance with Env-A 809; c. A stack volumetric flow measuring device shall meet the following requirements: i. All differential pressure flow monitors shall have an automatic blow-back purge system installed and, in wet stack conditions, shall have the capability for drainage of the sensing lines; and ii. The stack flow monitoring system shall have the capability for manual calibration of the transducer while the system is on-line and for a zero check; and d. Alternatives to in-stack flow monitoring devices for determination of stack volumetric flow rate may be used if the owner or operator provides the division with technical justification that the alternative can meet the same requirements for data availability, data accuracy, and quality assurance as an in-stack device.	Continuously	Env-A 808.03
6.	EU17	NOx CEM	CEM Monitoring Plan: a. The owner or operator shall submit to the division, at least 90 days prior to the installation of the CEM system, a CEM monitoring plan describing the system. b. Upon receipt of the CEM monitoring plan, the division shall:	Due at least 90 days prior to the installation of the CEM system	Env-A 808.04

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			i. Review the plan for compliance with all the elements described in this section; ii. Determine whether the CEM meets all the requirements of this part; and iii. Issue its decision within 30 days. c. The monitoring plan shall provide the following: i. A complete description of the emission monitoring system including, but not limited to: A. The identity of the CEM system vendor, including the company name, address, and telephone number; B. The identity of the manufacturer, model number, measurement method employed, and range of each of the major components or analyzers being used; C. A description of the sample gas conditioning system; D. A description and diagram showing the location of the monitoring system, including sampling probes, sample lines, conditioning system, analyzers, and data acquisition system; and E. A description of the data acquisition system, including sampling frequency, and data averaging methods; ii. The mathematical equations used by the data acquisition system, including the value and derivation of any constants, to calculate the emissions in terms of the applicable emission standards; iii. An example of the data reporting format; iv. A description of the instrument calibration methods, including the frequency of calibration checks and manual calibrations, and path of the sample gas through the system; v. The means used by the data acquisition system of determining and reporting		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			periods of excess emissions, monitor downtime, and out-of-control periods; and vi. A description of the means used to provide for short-term and long-term emissions data storage.		
7.	EU17	NOx CEM	<u>Performance Specification Testing:</u> The owner or operator shall conduct performance specification testing for a CEM system in accordance with the following: a. For a CEM system monitoring gaseous emissions, the performance specification requirements of 40 CFR 60, Appendix B, shall apply; b. All performance specification testing shall be conducted within 180 days of the CEM equipment initial startup; c. The division shall be notified of the date or dates of the performance specification testing at least 30 days prior to the scheduled dates; and d. A written report summarizing the results of the testing shall be submitted to the division within 30 days of the completion of the test.	As specified within regulation	Env-A 808.05
8.	EU17	NOx CEM QA/QC Plan	<u>Quality Assurance/Quality Control Plan Requirements:</u> a. The owner or operator shall: i. Prepare a quality assurance/quality control (QA/QC) plan, which shall contain written procedures for implementation of its QA/QC program for each CEM system; ii. File the QA/QC plan with the division no later than the time specified in Env-A 808.05(e) after the initial startup of each CEM system (within 30 days of the completion of the performance specification test). iii. Review the QA/QC plan and all data generated by its implementation at least once each year; iv. Revise or update the QA/QC plan, as necessary, based on the results of the annual review, by: A. Documenting any changes made to the CEM or changes to any information provided in the	As specified within regulation	Env-A 808.06

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			monitoring plan; B. Including a schedule of, and describing, all maintenance activities that are required by the CEM manufacturer or that might have an effect on the operation of the system; C. Describing how the audits and testing required by this part will be performed; and D. Including examples of the reports that will be used to document the audits and tests required by this part; v. Make the revised QA/QC plan available for on-site review by the division at any time; and vi. Within 30 days of completion of the annual QA/QC plan review, certify in writing that the owner or operator will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reasons for each change; b. The division shall request revision of the QA/QC plan if the results of emission report reviews, inspections, audits, review of the QA/QC plan, or any other information available to the division show that the plan does not meet the criteria specified in 40 CFR 60, Appendix F, Procedure 1, section 3; and c. The QA/QC plan shall be considered an update to the CEM monitoring plan required by Env-A 808.04.		
9.	EU17	NOx CEM Audit	<u>General Audit Requirements for All CEM Systems:</u> a. Required quarterly audits shall be done anytime during each calendar quarter, but successive quarterly audits shall occur no more than 4 months apart. b. Within 30 calendar days following the end of each quarter, the owner or operator shall submit to the division a written summary report of the results of all required audits that were performed in that quarter, in accordance with the following:	As specified within regulation	Env-A 808.07

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			16. For gaseous CEM audits, the report format shall conform to that presented in 40 CFR 60, Appendix F, Procedure 1, section 7. c. The owner or operator shall notify the division at least 30 days prior to the performance of a RATA. d. The division shall require the rescheduling of any RATA if the staff necessary to observe the audit is not available. e. The owner or operator shall provide at least 2 weeks' notice prior to any other planned audit or test procedure.		
10.	EU17	CEM Audit Require-ments	<u>Audit Requirements for Gaseous CEM System:</u> a. For a system monitoring gaseous emissions of NOx, CO, O2 or CO2, the quality assurance requirements and procedures described in 40 CFR 60, Appendix F, shall apply, with the following additions and clarifications for Procedure 1 of Appendix F: i. The owner or operator shall inform the division of all out of control periods, as defined in Appendix F, section 4.3, and Env-A 808.01(g), in the emission reports required pursuant to Env-A 808.11; ii. The owner or operator may perform a RAA, as defined in 40 CFR 60, Appendix F, in place of a CGA; and iii. For CEM systems where CGA audits cannot be performed, the owner or operator shall perform RAA audits in place of the CGA; b. For a time-shared gaseous CEM system, the owner or operator shall perform the following audits: i. An annual RATA to check the analyzer at any sampling point; and ii. CGAs or RAAs at all sampling points for each of the remaining 3 quarterly audits. c. The owner or operator determining compliance with a mass flow emissions limit by using a stack flow volumetric monitor or a fuel flow meter with O2/CO2 measurements to calculate heat input or stack flow rate, shall conduct annually a	As specified within regulation	Env-A 808.08

Table 8 – Monitoring and Testing Requirements					
Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			minimum 9-run RATA with the relative accuracy calculated in the units of the mass emissions measurement as specified in 40 CFR 60, Appendices B and F. d. In lieu of (c) above, the owner or operator of a stationary source using a fuel flow meter that meets the certification requirements of 40 CFR 75, Appendix D, may conduct the annual minimum 9-run RATA, as specified in 40 CFR 60, Appendix B, as follows: i. The RATA shall be performed on: A. The pollutant concentration in parts per million or pollutant pounds per million BTU; and B. The O2/CO2 diluent percentage; and ii. The relative accuracy requirements shall be: A. As specified in 40 CFR 60, Appendix B, 40 CFR 75, or ±1 ppm for the pollutant, as applicable; and B. As specified in 40 CFR 60, Appendix B, or 40 CFR 75, as applicable, for the percentage O2/CO2. e. For a stationary source subject to (c) above, and using a stack volumetric flow monitor for the mass flow emissions calculation, the owner or operator of such source shall also perform one of the following audit options: i. An audit that shall consist of: A. A 3-run RAA, which shall be conducted in 2 of the calendar quarters in which the RATA specified in (c) is not conducted: 1. To determine the percentage accuracy of the source's stack flowrate measurement method; and 2. To compare the source's method of determining stack flowrate against the compliance method of measuring the stack flowrate, as follows:		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			I. A velocity traverse shall be conducted following Methods 1 and 2 of 40 CFR 60, Appendix A; II. A calculation of average wet standard cubic feet per hour shall be measured for each run using a stack gas molecular weight and percent stack moisture from either the stack flow monitor or the most recent Methods 3 and 4 measurement made at the subject source; III. A leak check shall be performed after completion of the velocity traverse in accordance with 40 CFR 60, Appendix A, Method 2, part 3.1; IV. The thermocouple used for measurement of stack gas temperature shall be calibrated annually; V. Steps (I) through (III) shall be repeated 2 more times to result in 3 compliance measurements of the stack volumetric flowrate; VI. A percentage accuracy calculation shall be performed as follows: a. "WSCFH, CEM" means the 3-run average of the wet standard cubic feet per hour flow rate as determined by the stack flow monitor method; b. "WSCFH, M2" means the 3-run average of the wet standard cubic feet per hour as measured by the Method 1 and Method 2 procedures; c. To calculate the		

Table 8 – Monitoring and Testing Requirements

Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			percentage accuracy of the monitor, the owner or operator shall calculate the difference between WSCFH, CEM and WSCFH, M2, divide the difference by the value of WSCFH, M2, and then multiply the result by 100, as in the formula below: % Accuracy = ((WSCFH,CEM - WSCFH,M2)/(WSCFH,M2)) x 100 VII. The absolute value of percentage accuracy shall be less than or equal to 10.0% for the monitor to pass the audit; and VIII. If the percentage accuracy exceeds 10.0%, the monitor shall be considered "out of control" until necessary repairs/adjustments are performed to the system and the monitor successfully passes the percentage accuracy requirements, as determined by a repeat audit; and B. In the remaining quarter in which the RATA specified in (c) and the RAA are not performed, a calibration of the transmitter or transducer, as applicable, of the stack flowrate or fuel flow monitor following the manufacturer's recommended calibration procedure; or ii. An audit, to be performed in each calendar quarter in which the RATA specified in (c) above is not conducted, which shall consist of: A. A flow monitor differential-pressure sensing lines' leak check		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			for low and high-pressure sides; B. A stack flow probe inspection, including removal and cleaning of the probe as necessary; C. A differential pressure transmitter/transducer calibration following the manufacturer's recommended calibration procedure; and D. A continuous flow-to-load-ratio or gross heat rate evaluation in accordance with 40 CFR 75, Appendix B. f. The owner or operator of a stationary source subject to (c) above, and using a fuel flow monitor for the mass flow emissions calculation, shall also perform one of the following audit options: i. The quality assurance activities on the fuel flow monitor as specified in 40 CFR 75, Appendix D; or ii. The audit specified in (e)(i) above.		
11.	EU17	CEM Data Availability Require-ments	Data Availability Requirements: a. The owner or operator of a source with a CEM shall operate the CEM at all times during operation of the source, except for periods of CEM breakdown, repairs, calibration checks, preventive maintenance, and zero/span adjustments. b. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 90% on a calendar quarter basis. c. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 75% for any calendar month. d. The percentage CEM data availability shall be calculated as follows: i. "VH" means the number of valid hours of CEM data in a given time period for which the data availability is being calculated when the plant is in operation; ii. "OH" means the number of facility operating hours during a given time period for which the data availability is	As specified within regulation	Env-A 808.10

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			being calculated; iii. "AH" means the number of hours during facility operation when the performance of quarterly audits as required by those procedures specified in Env-A 808.08, as applicable, require that the CEM be taken out of service in order to conduct the audit; iv. "CalDT" means the number of hours, not to exceed one hour per day, during facility operation when the CEM is not operating due to the performance of the daily CEM calibrations as required in 40 CFR 60, Appendix F or 40 CFR 75, Appendix B, section 2.1.; and v. To calculate the percentage CEM data availability, multiply the sum of VH and CalDT by 100, and divide the result by the difference between OH and AH, as in the formula below: $PercentageDataAvailability = \frac{(VH + CalDT)x100}{(OH - AH)}$ e. If the percentage data availability requirements cannot be met for any calendar quarter, the owner or operator of the source shall: i. Submit a plan to the division within 30 days of the end of the quarter of failure to meet the data availability requirements specifying in detail the steps to be taken in order to meet the availability requirements for the current quarter and future quarters; and ii. Implement the plan to meet the data availability requirements no later than 30 days after the end of the quarter of failure. f. If the percentage data availability requirements cannot be met for any 2 consecutive calendar quarters, the owner or operator of the source shall: i. Install a replacement CEM system meeting all of the requirements of 40 CFR 60, Appendix B, Specifications 1-6 in accordance with the following		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			deadlines: A. The replacement CEM system shall be installed and operational no later than 180 days following the end of the second quarter of failure to meet the data availability requirements; and B. Certification testing of the replacement CEM system shall be initiated no later than 210 days following the end of the second quarter of failure to meet the data availability requirements; and ii. During the period of time from the end of the second quarter of failure to meet the data availability requirements until the successful certification testing completion of the replacement CEM system: A. Maintain the quality of data obtained from the currently operating CEM and maximize data availability of the CEM; or B. Replace the existing CEM with a temporary alternative that shall monitor the compliance status of the emission point of concern. g. Alternatives to the replacement of the entire CEM system as required by paragraph (f) above, shall be allowed provided that the facility can provide the division with technical justification that the alternative will ensure that the 90% data availability requirement shall be met on a consistent basis.		
12.	EU17	NOx CEM	<u>Valid Averaging Periods:</u> The number of hours of valid CEM data required for determining a valid averaging period for the different emission standard periods shall be: a. For a 3-hr emission standard period, 2 hours of valid data; b. For a 4-hr standard emission standard period, 3 hours of valid data; c. For a 8-hr standard emission standard period, 6 hours of valid data; d. For a 12-hr standard emission standard	As specified within regulation	Env-A 808.14

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			period, 9 hours of valid data; and e. For a 24-hr standard emission standard period, 18 hours of valid data.		
13.	EU17	Use of NOx CEM data	<u>Use of CEM Data:</u> The division shall use CEM data either directly or indirectly for the following: a. Compliance determinations; b. Air quality impact analysis; c. Air pollution dispersion modeling; d. Control technology review; and e. Emissions inventory.	As specified within regulation	Env-A 808.15
14.	Facility wide	Approval of alternate methods or require-ments	<u>Approval of Alternate Methods or Requirements:</u> For any testing or monitoring procedure that is an alternative to a method or requirement specified by these rules, the following procedure shall apply: a. The owner or operator of a source seeking approval of an alternative shall submit to the director the following information: i. A description of the proposed alternate method or requirement; ii. The identity of the compound that is to be tested or controlled or the equipment that is to be maintained by the alternate method or requirement; iii. The identity and description of the source at which the alternate method or requirement will be implemented; and iv. Technical data and information demonstrating that the purpose of the specified method or requirement will be achieved by the alternate method or requirement and that the alternative produces results that are no less precise and accurate than those produced by the specified method or requirement; and b. Within 60 days of receipt of a complete application that meets the requirements of (a) above, the director shall: i. Review the application; ii. Issue a written decision: A. Approving the application if the department determines that the alternate method or requirement: 1. Achieves the purpose of the specified method or	Upon request by owner or operator	Env-A 809.01

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			requirement; and 2. Produces results that are no less precise and accurate than those produced by the specified method or requirement; or B. Denying the application and specifying the reason(s) for the denial; and iii. Notify the applicant and USEPA of the decision.		
15.	Facility wide	Approval of alternate methods or requirement for federal standards	Alternate Methods for Federal Standards: Alternate test methods for compliance with federal standards, such as those specified in 40 CFR 60, 61, and 63, shall be submitted by the owner or operator of the source to USEPA for approval.	Upon request by owner or operator	Env-A 809.02
16.	PC1/EU16	Thermal Oxidizer Combustion Tempera-ture	a. The owner or operator shall monitor and record the temperature in the combustion chamber.	Continuous	Env-A 906
			b. If the temperature reading is less than the minimum specified in Table 6, Item 11.a, then inspect the unit and take corrective action to raise the temperature	As noted	
17.	PC1/EU16	Thermal Oxidizer Inspection	Conduct a visual external integrity inspection of the thermal oxidizer. a. The inspection shall include an evaluation of whether all emissions are being vented through the dedicated stack exit. b. The inspection shall be conducted by plant personnel familiar with the operation of the oxidizer and associated equipment.	Annually and as conditions indicate it inspection is warranted	Env-A 604.01
18.	EU12 EU13 EU17	Electrical Power Generation	Determine electrical power generation by either of the following methods: a. By calculating actual electrical power generation in MW-hr by multiplying the heat input in MMBtu obtained from fuel use records by 0.10 MW-hr/MMBtu; or b. By monitoring electrical power generation in kW-hr using one of the monitors specified in Env-A 3705.01(b)(1).	Continuous	Env-A 3705.01
19.	EU17	NOx	a. The owner or operator must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine (the limit is 96 ppm @15% O_2), the owner or operator may	Continuous	40 CFR § 60.4340

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, the owner or operator must resume annual performance tests. b. As an alternative to (a) above, the owner or operator may install, calibrate, maintain and operate one of the following continuous monitoring systems: i. Continuous emission monitoring as described in 40 CFR §60.4335(b) and 40 CFR §60.4345, or ii. Continuous parameter monitoring as follows: A. For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, the owner or operator must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously. B. For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOX mode. C. For affected units that are also regulated under 40 CFR Part 75, with DES approval the owner or operator can monitor the NOx emission rate using the methodology in appendix E to 40 CFR Part 75, or the low mass emissions methodology in 40 CFR §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of 40 CFR Part 75 appendix E or in 40 CFR §75.19(c)(1)(iv)(H).		
20.	EU17	NOx	If the option to use a NOx CEMS is chosen to demonstrate continuous compliance with the 40	Continuous	§ 60.4345

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			CFR Part 60 Subpart KKKK requirements for NOx, the following requirements shall apply: a. Each NOx diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B of 40 CFR Part 60, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to 40 CFR Part 60 is not required. Alternatively, a NOx diluent CEMS that is installed and certified according to appendix A of 40 CFR Part 75 is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis. b. As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour. c. Each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to 40 CFR Part 75 are acceptable for use. d. Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions. e. The owner or operator shall develop and		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) above. For the CEMS and fuel flow meters, the owner or operator may, with DES approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to 40 CFR Part 75.		
21.	EU17	NOx	<u>Using CEM data to identify excess emissions</u> For purposes of identifying excess emissions: a. All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h). b. For each unit operating hour in which a valid hourly average, as described in item 2(b) above (40 CFR §60.4345(b)), is obtained for both NOx and diluent monitors, the data acquisition and handling system must calculate and record the hourly NOx emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in appendix A of this 40 CFR Part 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 v(as applicable) may be used in the emission calculations. c. Correction of measured NO_X concentrations to 15 percent O_2 is not allowed. d. If the owner or operator has installed and certified a NO_X diluent CEMS to meet the requirements of 40 CFR Part 75, DES can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR §60.7(c). e. All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages. f. Calculate the hourly average NOx emission rates, in units of the emission standards	Continuous	40 CFR § 60.4350

Table 8 – Monitoring and Testing Requirements

Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			under 40 CFR §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard: i. For simple-cycle operation: $E = \frac{(NO_X)_h * (HI)_h}{P}$ (Eq. 1) Where: E = hourly NO_X emission rate, in lb/MWh, $(NO_X)_h$= hourly NO_X emission rate, in lb/MMBtu, $(HI)_h$= hourly heat input rate to the unit, in MMBtu/hr, measured using the fuel flowmeter(s), *e.g.* , calculated using Equation D–15a in Appendix D to 40 CFR Part 75 of this chapter, and P = gross energy output of the combustion turbine in MW. ii. For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations: $P = (Pe)_t + (Pe)_c + Ps + Po$ (Eq. 2) Where: P = gross energy output of the stationary combustion turbine system in MW. $(Pe)_t$= electrical or mechanical energy output of the combustion turbine in MW,		

Table 8 – Monitoring and Testing Requirements

Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			$(Pe)_c$= electrical or mechanical energy output (if any) of the steam turbine in MW, and $$Ps = \frac{Q * H}{3.413 \times 10^6 \text{ Btu/MWh}} \quad \text{(Eq. 3)}$$ Where: Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW, Q = measured steam flow rate in lb/h, H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413 x 10_6= conversion from Btu/h to MW. Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine. iii. For mechanical drive applications complying with the output-based standard, use the following equation: $$E = \frac{(NO_X)_m}{BL * AL} \quad \text{(Eq. 4)}$$ Where: E = NO_Xemission rate in lb/MWh, $(NO_X)_m$= NO_Xemission rate in lb/h, BL = manufacturer's base load rating of turbine, in MW, and AL = actual load as a percentage of the base load. g. For simple cycle units without heat recovery, use the calculated hourly average emission rates from condition (f) above to assess excess emissions on a 4-hour rolling average basis, as described in 40 CFR §60.4380(b)(1). h. For combined cycle and combined heat and power units with heat recovery, use the		

Table 8 – Monitoring and Testing Requirements					
Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in 40 CFR §60.4380(b)(1).		
22.	EU17	Sulfur content of turbine fuel	<u>Determining the total sulfur content of the turbine combustion fuel</u> a. The owner or operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in (b) below. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR §60.17), which measure the major sulfur compounds, may be used.	As specified within regulation	40 CFR §60.4360
			b. The owner or operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input. The following source of information must be used to make the required demonstration: i. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.		40 CFR §60.4365
			c. If the owner or operator elects not to demonstrate sulfur content using the option in (b) above (40 CFR §60.4365), and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.		40 CFR §60.4370
23.	EU17	Sulfur content of turbine fuel	<u>Custom schedules for determination of the total sulfur content of gaseous fuels</u>	As specified within regulation	40 CFR §60.4370

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			a. Notwithstanding the requirement of item (22)(c) above of this table, the owner or operator may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (b)(i) and (b)(ii) below of this permit condition, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in 40 CFR §60.4330. b. The two custom sulfur monitoring schedules set forth in paragraphs (i) through (iv) and in paragraph (c) below are acceptable without prior Administrative approval: i. The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (b)(ii), (iii), or (iv) below, as applicable. ii. If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures in paragraph (b)(iii) below. If any measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. iii. If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then:		

Table 8 – Monitoring and Testing Requirements

Item No.	Applicable Emission Unit	Parameter	Method of Compliance	Frequency of Method	Regulatory Cite
			A. Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, follow the procedures in paragraph (b)(iii)(B) below. B. Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, follow the procedures in paragraph (b)(iii)(C) below. C. Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, continue to monitor at this frequency. iv. If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (b)(i) above. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (b)(ii) or (iii) above shall be followed. c. The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of Appendix D to 40 CFR Part 75 to determine a custom sulfur sampling schedule, as follows: i. If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			purposes of 40 CFR Part 60 compliance. ii. If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals. iii. If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (b)(iii) above. iv. If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (b)(iv) above.		

D. **Recordkeeping Requirements**

The owner or operator is subject to the Recordkeeping requirements as contained in Table 9 below:

Table 9 – Applicable Recordkeeping Requirements

Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
1.	Record Retention and Availability: The owner or operator shall keep all records required by this permit on file for a minimum of 5 years.	Keep all records for a minimum of 5 years	Facility Wide	Env-A 902.01(a)
2.	Regulated Toxic Air Pollutant Records: The owner or operator shall maintain records in accordance with the applicable method used to demonstrate compliance pursuant to Env-A 1406.	Maintain at facility at all times	All devices subject to RSA 125-I and Env-A 1400	Env-A 902.01(c)
3.	Subject to Env-A 103, all data submitted to the division, including emission data and applicable emission limitations, shall be available to the public.	As specified in this permit	Facility Wide	Env-A 902.01(d)
4.	General Recordkeeping Requirements for Combustion Devices: The owner or operator of a combustion device shall maintain monthly records of fuel characteristics and utilization, including primary, secondary, tertiary and auxiliary fuels in accordance with the following: a. Consumption; b. Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel; and c. BTU content per cubic foot of fuel. d. Sources operating one or more combustion devices shall record the hours of operation of each combustion device so that the distribution of fuel among each combustion device can be estimated.	Monthly unless otherwise specified	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 903.03
5.	General Recordkeeping Requirements for Sources with Continuous Emissions Monitoring Systems: The owner or operator with a certified continuous emissions monitoring system subject to Env-A 800, shall maintain records in accordance with the provisions of Env-A 800, and all applicable federal regulations.	As required under Env-A 800 and by federal regulations	EU17	Env-A 903.04
6.	General Recordkeeping Requirements for NOx-emitting Generation Sources: Maintain the following records: a. Actual NOx emissions in accordance with the methods set forth in Env-A 616; b. Fuel usage; c. Hours of operation; d. Power generation as monitored pursuant to Table 8, item 18 of this permit; e. Hours of downtime of the power generation monitoring system, if applicable, during the time period when the generating unit is in operation; and f. Frequency and results of calibrations performed on	Monthly	EU12 EU13 EU17	Env-A 903.06 Env-A 3706.01(b)

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
	the power generation monitoring system, as applicable.			
7.	<u>General VOC Recordkeeping Requirements</u>: The owner or operator shall record and maintain the following information at the facility: a. Identification of each VOC-emitting process or device, except processes or devices associated exclusively with non-core activities, as defined in Env-A 1204.03(bp); b. The operating schedule during the high ozone season for each VOC-emitting process or device identified in (a), above, including: i. Hours of operation per calendar month; and ii. Days of operation per calendar month; c. The following VOC emission data: i. Actual VOC emissions from each VOC-emitting process or device identified in (a), above for: A. Each calendar year, in tons; and B. A high ozone season day during that calendar year, in pounds per day; and ii. The emission factors and the origin of the emission factors used to calculate the VOC emissions.	Annually and as applicable	Facility Wide	Env-A 904.02
8.	<u>General NOx Recordkeeping Requirements:</u> The owner or operator shall record and maintain the following information: a. Identification of each combustion device; b. Operating schedule during the high ozone season for each combustion device identified in (a), above, including for each device: i. The typical hours of operation per day; ii. The typical days of operation per calendar month; iii. Number of weeks of operation; iv. Type and amount of fuel burned; v. Heat input rate in million BTUs per hour or, for incinerators, in tons per hour; and vi. The following NO_x emission data: A. Actual calendar year NOx emissions; B. The typical high ozone season day NOx emissions, in pounds per day; and C. The emission factors and the origin of the emission factors used to calculate the NOx emissions.	Annually and as applicable	Facility Wide	Env-A 905.02

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
9.	Additional Recordkeeping Requirements: The Owner or Operator shall maintain a 12-month running total record of emissions of NOx, SO2, CO, TSP, PM10, and VOC for the purpose of demonstrating that emissions of these pollutants are below the facility wide caps in Table 5 of this permit.	Monthly calculation of 12-month rolling average	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 906
10.	Thermal Oxidizer Records: The owner or operator shall maintain records of all air pollution control equipment activities required in items 16 and 17 of Table 8, including: a. The monthly hours of operation; b. Records of thermal oxidizer combustion temperature monitoring; c. A log of repairs made to the thermal oxidizer. The log shall include the following: i. The date a problem was observed; ii. The date of the repair; iii. A description of the problem; and iv. The corrective actions taken.	As specified in items 16 and 17 of Table 8 of this permit	PC1/EU16	Env-A 906
End of State Requirements – Start of Federal Requirements				
11.	NSPS Startup, Shutdown, Malfunction Records: The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; any malfunction of the air pollution control equipment; or any periods during which a CEMS or monitoring device is inoperative.	For each startup, shutdown, malfunction or period where CEMS or monitoring device is inoperative	EU17	40 CFR 60.7 (b)
12.	Retention of NSPS Records: a. The owner or operator shall maintain all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR 60 Subpart KKKK recorded in a permanent form suitable for inspection. b. The file in (a) above shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: i. This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated	All NSPS records to be maintained for 2 years unless otherwise specified	EU17	40 CFR 60.7 (f)

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
	data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under item (a) above, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. ii. This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under (a) above, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. iii. The Administrator or DES, upon notification to the source, may require the owner or operator to maintain all measurements as required by (a) above, if the Administrator or DES determines these records are required to more accurately assess the compliance status of the affected source.			

E. **Reporting Requirements**

The owner or operator is subject to the federally enforceable reporting requirements identified in Table 10 below:

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
1.	General Reporting Requirements: a. The owner or operator of any stationary source, area source or device subject to Env-A 600 shall submit an annual emissions report. b. The annual emissions report pursuant to (a) above, shall include the following information: i. The actual emissions of the stationary source, area source or device and the methods used in calculating such emissions in accordance with Env-A 705.02; ii. For process operations, all information in accordance with Env-A 903.02; iii. For combustion devices, all information in accordance with Env-A 903.03; and iv. The actual annual emissions speciated by individual regulated air pollutants, including a breakdown of VOC emissions by compound. c. The annual emissions report pursuant to (a) above, shall be submitted to the division on or before April 15 of the following year. For calendar year 2007, the annual emissions report shall be submitted to the division on or before April 15, 2008.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.01
2.	Reporting Requirements for Sources Subject to the Acid Deposition Control Program. The owner or operator shall submit an annual report by April 15 of the following year containing the following information required pursuant to Env-A 903.03: a. Fuel consumption; b. Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel; and c. BTU content per cubic foot of fuel.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.02
3.	General Reporting Requirements for NOx-emitting Generation Sources. As provided in Env-A 3701.02, the owner or operator of a NOx-emitting generation source, as that term is defined in Env-A 3702, shall report annually by April 15 of the following calendar year, the data required pursuant to Env-A 903.06.	Annually (no later than April 15th of the following year)	EU12 EU13 EU17	Env-A 907.03
4.	VOC Emission Statements Reporting Requirements: a. If the actual facility-wide annual VOC emissions are greater than or equal to 10 tons, the owner or	Annually (no later than April 15th of the	Facility Wide	Env-A 908.02

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	operator shall submit all information pursuant to Env-A 908.03 as applicable, by April 15 of the following calendar year. b. For sources subject to (a) above, updated information specified below in items 5 and 6 below of this table shall be submitted to the division for each subsequent calendar year in which actual emissions equal or exceed 10 tons.	following year)		
5.	The owner or operator shall submit the following information to DES in accordance with the schedule set-forth in item 4 of this table, above: a. Facility information, including: i. Source name; ii. Standard Industrial Classification (SIC) code; iii. Physical address; and iv. Mailing address; b. Identification of each VOC-emitting process or device operating at the source identified in (a), above; c. Operating schedule during the high ozone season for each VOC-emitting process or device identified in (b), above, including: i. Hours of operation per calendar day; and ii. Days of operation per calendar week; d. Total quantities of actual VOC emissions for the entire facility and for each process or device identified in (b), above, including: i. Annual VOC emissions, in tons; and ii. Typical high ozone season day VOC emissions, in pounds per day.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 908.03(a)
6.	The owner or operator shall submit the following information to DES in accordance with the schedule set-forth in item 4 above of this table: a. Identification of each VOC-emitting process or device, except processes or devices associated exclusively with non-core activities, as defined in Env-A 1204.03(bp); b. The operating schedule during the high ozone season for each VOC-emitting process or device identified in (a), above, including: i. Hours of operation per calendar month; and ii. Days of operation per calendar month; c. The following VOC emission data: i. Actual VOC emissions from each VOC-emitting process or device identified in (a),	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 908.03(f)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	above for: A. Each calendar year, in tons; and B. A high ozone season day during that calendar year, in pounds per day; and ii. The emission factors and the origin of the emission factors used to calculate the VOC emissions.			
7.	NOx Reporting Requirements: The owner or operator shall submit reports of the NOx records kept pursuant to Table 9, Item 8 of this permit (this is the same information specified in Env-A 905.02).	Annually (no later than April 15th of the following year)	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 909.02 Env-A 909.03
8.	Prompt Reporting of Permit Deviations: The owner or operator shall promptly report deviations from permit requirements by phone, fax or e-mail in accordance with Section XIX of this permit.	Within 24 hours of discovery of occurrence	EU12 EU13 EU14 EU15 EU16 EU17	Env-A 911
9.	CEM Quarterly Emission Reports: Within 30 days of the end of each calendar quarter, the owner or operator shall submit an emission report to the division.	Quarterly, within 30 days of the end of each calendar quarter	EU17	Env-A 808.11
10.	Emission Reports for Sources Subject to 40 CFR 60. The owner or operator shall provide the following in each quarterly emission report specified in Env-A 808.11: a. The information specified in 40 CFR 60.7(c) and any applicable subpart of 40 CFR 60; b. The daily averages of gaseous CEM measurements and calculated emission rates; and c. The information required in (i) through (v) below (Env-A 808.13(a)(5) through (9)): i. If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: A. The date and time of the beginning and ending of each period when the CEM was inoperative; B. The reason why the CEM was not operating; C. The corrective action taken; and D. The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or polluant analyzer in the CEM system;	For each quarterly emission report required under condition (10) above	EU17	Env-A 808.12 and Env-A 808.13(a)(5) through (a)(9)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	ii. For all "out of control periods" as defined in Env-A 808.01(g) and 40 CFR 60, Appendix F, the following information: A. The times beginning and ending the out of control period; B. The reason for the out of control period; and C. The corrective action taken; iii. The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating; iv. The span value, as defined in Env-A 101.176, of each analyzer in the CEM system and units of measurement for each instrument; and v. When calibration gas is used, the following information: A. The calibration gas concentration; B. If a gas bottle was changed during the quarter: 1. The date of the calibration gas bottle change; 2. The gas bottle concentration before the change; and 3. The gas bottle concentration after the change; and C. The expiration date for all calibration gas bottles used.			
End of State Requirements – Start of Federal Requirements				
11.	The owner or operator shall furnish the USEPA Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows: a. A notification of the date construction (or reconstruction as defined under 40 CFR §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form. b. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date. c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR §60.14(e). This notice shall be postmarked 60 days	As specified within regulation	EU17	40 CFR §60.7(a)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice. d. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR §60.13(c). Notification shall be postmarked not less than 30 days prior to such date. e. The address for USEPA Region 1 is: USEPA Region 1 Attn: Air Compliance Clerk 1 Congress Street Suite 1100 Mail Code SEA Boston, MA 02114-2023			
12.	<u>Semiannual Excess Emissions and Monitoring Systems Report:</u> a. The owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in 40 CFR §60.4350 and 40 CFR §60.4380) and/or summary report form (see (b) below) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: i. The magnitude of excess emissions computed in accordance with 40 CFR §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period. ii. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action	Semiannually, postmarked by the 30th day following the end of each six-month period	EU17	40 CFR §60.7(c)-(d) 40 CFR §60.4375(a)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	taken or preventative measures adopted. iii. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. iv. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. b. The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR §60.7(d) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility. i. If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR §60.7(c) need not be submitted unless requested by the Administrator. ii. If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR §60.7(c) shall both be submitted.			

General Temporary Permit and PSD Permit Conditions

IX. Temporary Permit Renewal Procedures

Pursuant to Env-A 607.02(b), for the reissuance of a temporary permit, an application shall be considered timely if it is received by the department at least 90 days prior to the designated expiration date of the temporary permit.

X. Application Shield

A. Pursuant to Env-A 607.10(a), if an applicant submits a timely application that has been deemed complete by the department for the reissuance of a temporary permit or the issuance of an initial state permit to operate, the failure to have a current and valid temporary permit shall not be considered a violation of RSA 125-C:11,I or Env-A 607.01 unless and until the department takes final action on the application by denying the requested reissuance of a temporary permit or issuance of a state permit to operate.

B. Pursuant to Env-A 607.10(b), if the department deems an application complete, but requests additional information pursuant to Env-A 607.06(b), the protection granted in Env-A 607.10(a) shall cease to apply when the applicant fails to submit in writing such additional requested information by the deadline specified in the request.

XI. Permit Shield

Pursuant to Env-A 607.08(c), the expiration of a temporary permit shall terminate the owner or operator's right to construct or operate a new or modified source or device pursuant to the permit, unless a timely and complete application for a state permit to operate, title V operating permit, or an amendment thereto, has been received by the department. Upon the submittal of a timely and complete application for any of the foregoing permits, the right to construct shall continue, under the terms and conditions of the expired temporary permit, pending the department's decision on the application.

XII. Administrative Permit Amendments

A. An administrative permit amendment includes the following:
   1. Corrects typographical errors;
   2. Requires more frequent monitoring or reporting; or
   3. Allows for a change in ownership or operational control of a source provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

B. The owner or operator may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

XIII. Minor Permit Amendments

A. The owner or operator shall submit to the Division a request for a minor permit amendment for any proposed change to any of the conditions contained in this permit which will not result in an increase in the amount of a specific air pollutant currently emitted by the devices listed in

Condition VI.A and will not result in the emission of any air pollutant not emitted by the source or device.

B. The request for a minor permit amendment shall be in the form of a letter to the Division and shall include the following:
   1. A description of the proposed change; and
   2. A description of any new applicable requirements that will apply if the change occurs.

C. The Owner or Operator may implement the proposed change immediately upon filling a request for the minor permit amendment.

XIV. Significant Permit Amendments

A. The Owner or Operator shall submit a written request for a permit amendment to the Division at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the devices covered by this permit which increases the amount of a specific air pollutant currently emitted by such device or which results in the emission of any regulated air pollutant currently not emitted by such device.

B. A request for a significant permit amendment shall include the following:
   1. A complete application form, as described in Env-A 1703 through Env-A 1708, as applicable;
   2. A description of:
      a. The proposed change;
      b. The emissions resulting from the change;
      c. Any new applicable requirements that will apply if the change occurs; and
      d. Where air pollution dispersion modeling is required for a device pursuant to Env-A 606.02, the information required pursuant to Env-A 606.03.

C. The owner or operator shall not implement the proposed change until the Division issues the amended permit.

XV. Temporary Permit/PSD Permit Suspension, Revocation or Nullification

A. Pursuant to RSA 125-C:13, the Director may suspend or revoke any final permit issued hereunder if, following a hearing, the Director determines that:

   1. The owner or operator has committed a violation of any applicable statute or state requirement found in the New Hampshire Rules Governing the Control of Air Pollution, order or permit condition in force and applicable to it; or

   2. The emissions from any device to which this permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.

B. The Director shall nullify any permit, if following a hearing in accordance with RSA 541-A:30, II, a finding is made that the permit was issued in whole or in part based upon any information proven to be intentionally false or misleading.

XVI. Inspection and Entry

USEPA and DES personnel shall be granted access to the facility covered by this permit, in accordance with RSA 125-C:6,VII, for the purposes of: inspecting the proposed or permitted site; investigating a complaint; and assuring compliance with any applicable requirement or state requirement found in the NH Rules Governing the Control of Air Pollution and/or conditions of any permit issued pursuant to Chapter Env-A 600.

XVII. Reports

All reports submitted to DES (except those submitted as emission based fees as outlined in Section XVIII of this Permit) shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
ATTN: Section Supervisor, Compliance Bureau

All reports submitted to USEPA shall be submitted to the following address:

Office of Environmental Stewardship
Director Air Compliance Program
United States Environmental Protection Agency
1 Congress Street
Suite 1100 (SEA)
Boston, MA 02114-2023
ATTN: Air Compliance Clerk

XVIII. Emission-Based Fee Requirements

A. Env-A 705.01, *Emission-based Fees*: The Owner or Operator shall pay to the Division each year an emission-based fee for emissions from the devices listed in Condition VI.A of this permit.

B. Env-A 705.02, *Determination of Actual Emissions for use in Calculating of Emission-based Fees*: The Owner or Operator shall determine the total actual annual emissions from the devices listed in Condition II for each calendar year in accordance with the methods specified in Env-A 616, Determination of Actual Emissions. If the emissions are determined to be less than one ton, the emission-based fee shall be calculated using an emission-based multiplier of one ton.

C. Env-A 705.03, *Calculation of Emission-based Fees*: The Owner or Operator shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT$$

where:

FEE = The annual emission-based fee for each calendar year as specified in Env-A 705;
E = Total actual emissions as determined pursuant to Condition XVIII.B; and
DPT = The dollar per ton fee the Division has specified in Env-A 705.03(e).

D. Env-A 3704.01, *Calculation of NOx Emissions for One or More NOx Emitting Generation Sources Located at a Single Stationary Source*: The Owner or Operator shall calculate average monthly emissions from the generators using the following equation:

$$E_{total} = \left(A_{generator285} + A_{generator270}\right) - \frac{7 * \left(B_{generator285} + B_{generator270}\right)}{2000}$$

where:

E_{total} = The total NOx emissions in tons per month;
A = The actual NOx emissions in tons per month for each generator; and
B = The actual power generation for each generator in megawatt-hours of electricity produced per month.

E. Env-A 3704.02, *Calculation of NO_x Emissions for Replacement Sources With Increased Generation Capacity*: The Owner or Operator shall calculate the total NOx emissions attributable to the increase in the amount of generating capacity using the following equation:

$$E = \frac{\left(MW_{new} - MW_{old}\right)}{MW_{old}} * E_{total}$$

where:

E = The total NO_x emissions subject to fees in tons per month;
E_{total} = The total NO_x emissions as calculated in Condition XI.D;
MW_{new}= The total generation capacity from EU02 and EU03 after the replacement; and
MW_{old}= The total generation capacity from EU02 and EU03 before the replacement.

F. Env-A 3707.03, *Calculation of NO_x Emissions Reduction Fund Fees*: The NO_x emissions reduction fund fee shall be equal to the total tons of NO_x emissions calculated in accordance with Condition XVIII.D multiplied by the NO_x emissions reduction fund fee in dollars per ton as listed in Table 9:

Table 11 - NO_x Emissions Reduction Fund Fee

Time Period	NO_x Emissions Reduction Fund Fee (Dollars Per Ton)
January 1 to April 30	500
May 1 to September 30	1000
October 1 to December 31	500

G. Env-A 705.04, *Payment of Emission-based Fee*: The Owner or Operator shall submit, to the Division, payment of the emission-based fee and the NO_x emissions reduction fund fee by April 15th for emissions during the previous calendar year. For example, the fees for calendar year 2007 shall be submitted on or before April 15, 2008.

XIX. Permit Deviation

A. In the event of a permit deviation, The owner or operator shall:

1. Investigate and take corrective action immediately upon discovery of the permit deviation to restore the affected device, process, or air pollution control equipment to within allowable permit levels; and

2. Record the following information:

    a. The permit deviation;
    b. The probable cause of the permit deviation;
    c. The date of the occurrence;
    d. The duration;
    e. The specific device that contributed to the permit deviation; and
    f. Any corrective or preventative measures taken.

3. If the permit deviation does not cause excess emissions, but continues for a period greater than 9 consecutive days, the source shall notify the division by telephone or fax on the tenth day of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday, of the subsequent corrective actions to be taken.

4. In the event of a permit deviation that causes excess emissions, The owner or operator of the affected device, process, or air pollution control equipment shall:

    a. Notify the division of the permit deviation and excess emissions by telephone or fax, within twenty-four (24) hours of discovery of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday; and

    b. Submit a written report, in accordance with (A)(6) below, to the division within ten (10) days of discovery of the permit deviation reported in (A)(4)(a), above.

5. In the event of a permit deviation caused by a failure to comply with the data availability requirements of Env-A 800, The owner or operator of the source shall:

    a. Notify the division of the permit deviation by telephone or fax, within 10 days of discovery of the permit deviation; and

    b. Report the permit deviation to the division, as part of the excess emissions report submitted in accordance with Env-A 800.

6. The written report, pursuant to (A)(4)(b) above, shall include the following information:

    a. Facility name;
    b. Facility address;
    c. Name of the responsible official employed at the facility;
    d. Facility telephone number;

e. Date(s) of the occurrence;
f. Time of the occurrence;
g. Description of the permit deviation;
h. The probable cause of the permit deviation;
i. Corrective action taken to date;
j. Preventative measures taken to prevent future occurrences; and
k. Date and time that the device, process, or air pollution control equipment returned to operation in compliance with an enforceable emission limitation, or operating condition;
l. The specific device, process or air pollution control equipment that contributed to the permit deviation;
m. The type and quantity of excess emissions emitted to the atmosphere due to the permit deviation; and
n. The calculation or estimation used to quantify the excess emissions.

B. In accordance with 40 CFR Part 70.6(a)(3)(iii)(A), sources subject to Env-A 609 that have been issued a title V permit, shall report to the division, at a reporting frequency no less stringent than semi-annually, the following information:

1. A summary of all permit deviations previously reported to the division pursuant to Env-A 911.04(a) and (b), for the reporting period;
2. A list of all permit deviations recorded pursuant to Env-A 911.03(b).

C. Sources subject to Env-A 607, Env-A 608, or Env-A 609 that have not been issued a title V permit, but have been issued a state permit to operate or a temporary permit, shall report to the division, at least annually by April 15, all information pursuant to (B) above.

XX. Discrete Emission Reduction Trading Program (Env-A 3100)

To date, the owner or operator did not file a notice of generation of Discrete Emissions Reductions (DERs) in accordance with Env-A 3100 nor a request for Emissions Reductions Credits (ERCs) in accordance with Env-A 3000. At this point, DES has not included any permit terms authorizing emissions trading in this permit. All emission reduction trading must be authorized under the applicable requirements of either Env-A 3000 *Emissions Reductions Credits Trading Program,* or Env-A 3100 *Discrete Emissions Reductions Trading Program* and 42 U.S.C § 7401 et seq. (The "Act"), and must be provided for in this permit.

XXI. Emissions Offset Requirements (Env-A 618.04)

Prior to commencing operation for this project, UNH shall demonstrate that NOx offsets have been obtained in a ratio of 1.2 to 1.0. Such emission offsets shall be real, surplus, quantifiable, permanent and federally enforceable and shall be certified by DES in accordance with all applicable state and federal regulations, including Env-A 3000.